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Interior to Lower Mainland
Transmission Reinforcement Options

Kelly Lake to Cheekye Substation Second 500 kV Transmission Line

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System Transmission Planning Department
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INTERIOR TO LOWER MAINLAND
TRANSMISSION REINFORCEMENT OPTIONS

1. EXECUTIVE SUMMARY

The purpose of this report is to identify and evaluate practical options for increasing the transfer capability of the BC Hydro Interior to Lower Mainland (Int-LM) 500 kV transmission grid. The need for this increase by the 1995/96 probable peak load was identified in Report No. SP9009, Reference [1].

This report includes a study of approximately 35 transmission and non-transmission options. It recommends that the following options be considered in Report No. SP9011, Reference [2], when developing and evaluating Int-LM 500 kV grid reinforcement plans:

a) Kelly Lake to Cheekye 500 kV Transmission Line No.2 (5L46)
b) Static Var Compensators at 500/230 kV Substations
c) Nicola to Meridian 500 kV Transmission Line No.2 (5L83)
d) Permanent Increase to 65% Series Compensation of Int-LM Lines
e) Switching Station at Ruby Creek
f) Adding 50% Series Compensation to Circuit 5L87

As well, BC Hydro should continue with its current practice of:

- encouraging Lower Mainland and Vancouver Island Demand Side Management and;
- using shunt capacitors to provide pre-outage voltage support while reserving dynamic vars for post-disturbance voltage stability.

This report also makes a number of other recommendations in Section 10, the most significant of which is that circuits 5L46 (Kelly Lake to Cheekye 500 kV No.2) and 5L83 (Nicola to Meridian 500 kV No.2) be used together to form an Int-LM reinforcement strategy which maximizes the increase in Int-LM transfer capability while minimizing net unit cost.

The study method was to first identify all options which could feasibly increase the Int-LM transmission capacity. The options were then screened and ranked in terms of relative merit based on technical, economic, and other factors. A ranking from a high of nine to a low of one established the order of merit of the options and only those that ranked more than five were carried through to a second stage of review. This second review of the options included a more detailed evaluation of the relative increase in transmission capacity, cost, and technical feasibility of options for service in the mid-1990's.

2. INTRODUCTION

Reference [1] showed that the Interior to Lower Mainland (Int-LM) portion of BC Hydro's 500 kV grid requires reinforcement by the Fall of 1995 to reliably serve the forecast load growth in the Lower Mainland and Vancouver Island region, in accordance with the BC Hydro system planning criteria. This report identifies and quantifies the viable conventional and non-conventional transmission options which may be used to achieve the required reinforcement.

A initial review screened all options which could reasonably be used to increase the Int-LM transfer capability. Engineering judgement was used to rank each option between 1 and 9. A subsequent review yielded the following classes of options, in order of descending merit:

- Class A, for inclusion in the long-term system plans in [2];
- Class B, for use to back up the Class A options;
- Class C, for use pending a change in technical and economic factors;
- Class D, not valid planning options but may be used to increase operating flexibility.

The balance of this report is organized as follows:

Section 3: A description of the study system;

Section 4: Study methods and assumptions;

Section 5: Reinforcement option categories;

Section 6: Class A and Class B options;

Section 7: Class C and Class D options;

Section 8: Factors beyond normal Planning Criteria;

Section 9: Conclusions;

Section 10: Recommended list of useable options.

3. THE INTERIOR TO LOWER MAINLAND GRID

The study portion of the Int-LM 500 kV grid is shown in Figure 1 in Appendix 1. The study system includes five 500 kV lines (5L41, 5L42, 5L81, 5L82, 5L87) bounded:

a) in the north by Kelly Lake Substation which integrates Peace River/Kemano generation;

b) in the east by Nicola Substation which integrates South Interior, West Kootenay Power, and Transalta generation;

c) in the west by Cheekye Substation which supplies the Sunshine

Coast[1] and a major portion of the Vancouver Island load and;

d) in the south by Meridian and Ingledow substations which serve the Lower Mainland as well as some Vancouver Island load. Two 500 kV lines connect Ingledow Substation to the Bonneville Power Administration (BPA) system.

Additional Int-LM connections are provided by two 230 kV circuits from Kelly Lake to Cheekye via the 500 MW Bridge River hydroelectric plant and one 360 kV circuit from Bridge River to Rosedale Substation located in the eastern Fraser Valley.

Additional Vancouver Island connections are provided by two 138 kV AC cable circuits and a +260/-280 kV HVDC bi-polar circuit from Ingledow via Arnott Substation in Delta to Vancouver Island Terminal Substation (VIT) near Duncan. Approximately 450 MW of hydroelectric generation is located on Vancouver Island.

In addition to the 900 MW Burrard Thermal Plant, located in Port Moody, there is approximately 500 MW of hydroelectric generation in and around the Lower Mainland load centre.

Burrard Thermal has synchronous condenser capability on generator units 1 to 4; however, generator Units 5 and 6 can be run at 40 MW minimum output for additional reactive support if needed. Burrard is usually run in synchronous condenser mode.

4. METHODS AND ASSUMPTIONS

4.1 Option Development

Several in-house planning forums were held to ensure that all candidate options for Int-LM reinforcement were accounted for. Approximately 35 options were listed. After considering the technical, economic, lead time, and other factors, each option was assigned a rank from 1 (low) to 9 (high). As well, each option was put into a broad functional category ranging from A (Transmission Lines) to J (Load Displacement). The options are presented in Table 1 in Appendix 2 which shows each option's subjective rank as a horizontal black bar and associated numerical rank. The options are listed in decending rank with outstanding studies and consultations needed to verify each identified option.

Options ranked more than five, as well as selected lesser ranked options, were subjected to a further review consisting of a voltage stability study, the procurement of a planning level cost estimate, a system loss evaluation, and/or a feasibility study. Each option was eventually classified A, B, C, or D depending on its technical and economic effectiveness in providing the needed Int-LM transmission power transfer capability.

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[1] including Powell River and Howe Sound Pulp industrial loads

4.2 Study Methods for Options Rated Six and Above

a) Voltage Stability

Each option's effectiveness was measured by the increase in the 1994/95 system Int-LM transfer capability that it would provide.

The increase in Int-LM transfer capability provided by each option was determined by applying the same power flow and procedures that were used in [1], i.e. critical-outage voltage stability (QV) curves were calculated at two load levels 500 MW apart. The system capability (zero dynamic var reserve load level) was then found by linear interpolation. Note that Circuit 2L1 (BRT-CKY 230 kV #1) was not represented in any of the voltage stability simulations.

b) System Losses

The evaluation of savings in system losses attributed to a transmission line option is based on the change in peak (demand) and average (energy) line losses over all of the lines in the system. The average decrease in line losses is the product of the decrease in peak megawatt loss, as provided by the powerflow study, and the "loss factor" of the Int-LM system. Only I^2R losses (conductor heating losses) are considered because other losses, such as corona and insulator leakage, are relatively insignificant.

The line loss calculation procedure maximized the power transfer on the subject line assuming zero non-firm export to the USA, BC Hydro 500 kV buses fixed at 525 kV, and then calculated the change in real power loss, with and without, the subject line[2]. Circuit 2L1 was represented in all of the line loss simulations except in Option 1 where 2L1 would be replaced by Kelly Lake-Cheekye 500 kV #2 (5L46).

The above procedure was also used to calculate the effect on losses of increasing Int-LM series compensation to 65% or 80% (options 8 and 25, respectively), adding a switching station near Ruby Creek (Option 11), and converting Circuit 2L1 to 360 kV (options 6 and 7).

The change in system loss due to construction of a 360 kV High Phase Order transmission line from Kelly Lake to Cheekye via Bridge River G.S. (Option 34) was provided by Powertech in [4].

Static var compensator losses (options 4 and 22) were estimated to be one megawatt.

No loss change was attributed to temporarily boosting series compensation (Option 18) or adding line drop compensation (options 2 and 10) since these facilities are assumed active only during system disturbances.

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[2] losses calculated for the 1994/95 system winter peak load

c) Economic

Options were compared on the basis of net annual cost which was calculated as the annual cost of capital and operation less the annual benefit of reduced system losses. An option's economic efficiency (net unit cost) was measured by its net annual cost per megawatt of increased Int-LM transfer capability.

4.3 Study Assumptions

a) Technical

See [1] for powerflow basecase assumptions.

1. Sufficient shunt capacitors will be installed by 1994/95 to provide nominal pre-outage bus voltages without having to deplete dynamic var reserves.

2. Firm exports to Seattle City Light (SCL) and West Kootenay Power (WKP) have equal status with BC Hydro domestic loads.

3. The ultimate 500 kV circuit thermal limit is the 3000 ampere continuous overload capability of the substation buses.

b) Economic

1. The assumed 8% discount rate is BC Hydro's basic discount rate for economically evaluating competing projects. As well, a sensitivity was done at 5% discount rate which, at the time that the economic studies were done, was BC Hydro's discount rate for project optimization.

2. Direct cost estimates, in October 1990 dollars, were either prepared within BC Hydro or provided by Powertech. For some of the options studied by Powertech, the costs were provided by BC Hydro to ensure consistent estimating methods and assumptions.

3. The long-term marginal cost of electricity, delivered to the Lower Mainland load centre in 1990 dollars, was assumed to be 64 mills/kWh as provided by [6].

4. The assumed Int-LM transmission loss factor of approximately 0.60 was derived from the following mid-1990's operating assumptions:

Energy

- Integrated System load, incl. firm export: 53000 GW.h

- LM/VI load, incl. losses[3]:	37100 GW.h
System secondary (off-peak) energy:	6000 GW.h
Total LM/VI load, incl. non-firm export[4]:	43100 GW.h
- LM/VI generation, incl. Burrard:	10000 GW.h
Int-LM annual energy transfer:	33100 GW.h

Capacity

- Integrated System peak load:	9100 MW
- LM/VI peak load, incl. losses[5]:	6370 MW
LM/VI dependable generation, incl. losses:	1138 MW
Int-LM peak load transfer:	5232 MW

Int-LM Loss Factor

- Int-LM Capacity Factor[6]:	0.72
Int-LM Loss Factor[7]:	0.58

5. OPTION CATEGORIES

This section provides a brief description of each category (A to J) of system reinforcement. Specific option details are presented in Sections 6 and 7.

Category A: TRANSMISSION LINES

The three-phase transmission line is the fundamental element of the electric transmission system, i.e. without it no electric power can flow from the generator to the load. Adding a transmission line increases thermal, transient, and voltage stability limits. The transmission line is the only option which significantly repays its cost through reduced system losses.

Transmission lines will have an impact on the local environment including nearby communities. The regulatory approval process and long construction periods make transmission lines long lead time options.

Category B: GENERATOR VOLTAGE/VAR CONTROL SCHEMES

A generator voltage/var control scheme will extract the maximum benefit from a generator's dynamic var reserve in support of load voltage during a system disturbance. The Joint Var Control (JVC) part of the scheme allows all of the generators at a given plant to share bus voltage control. The line drop compensation (LDC) part of the scheme allows the generators to control bus

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[3] 70% of 53000 GW.h

[4] LM/VI load + loss + non-firm export

[5] 70% of Integrated System peak load.

[6] 33,100,000 GW.h/(5230 MW * 8.76)

[7] 0.7 * 0.72**2 + 0.3 * 0.72

voltage remote from the generator terminals.

Generator voltage/var schemes extend system voltage stability limits. Lead times to implement are short.

Category C: PROVISION OF DYNAMIC VARS

This category increases voltage stability limits and includes:

a) Shunt Capacitor Additions

Nominal pre-outage system voltage can be maintained in an environment of real and reactive load growth by either increasing generator reactive output or by adding load centre shunt capacitors. The former represents an inefficient use of valuable dynamic vars because it leads to increased real and reactive losses and a greater risk of single-contingency voltage collapse. The latter, on the other hand, makes use of inexpensive shunt capacitors to flatten the pre-outage voltage profile (thereby reducing system real and reactive losses) while it reserves expensive dynamic vars for the outage. Issues related to shunt capacitor use include bus voltage change during switching and the frequency of switching. Coordination with the Area Transmission shunt capacitor requirements can yield cost savings.

b) Static Var Compensators (SVC)

SVC's are reactor/capacitor combinations which provide near instantaneous reactive power injection in support of system voltage during disturbances. SVC's can consume up to a megawatt in pre-outage losses. BC Hydro's first experience with this technology will be with the Dunsmuir Substation SVC due to come on line in 1993.

SVC's require complex control and protection schemes. Their principal advantage, compared to switched shunt devices, is that they can control system voltage during the post-disturbance transient period when the dynamic load characteristic is not well defined. Technical issues include having to avoid harmonic resonances.

c) Burrard Thermal Synchronous Condenser Operation

Four of the six generating units have been modified to allow operation as synchronous condensers. A Burrard unit operating in synchronous condenser mode (i.e. only reactive power output) provides continuous and near-instantaneous voltage control similar to that provided by SVC's. Losses would be the same or more when running as a turbine-generator unit due to additional windage. The switchover from condenser to generator mode can take up to seven days to complete. The lead time to modify the remaining two generators to be suitable for synchronous condenser/generator operation is approximately two years.

d) Load Centre Coordinated Var Control

Load centre coordinated var control refers to the provision of controls and suitable switching to enable coordinated voltage control during system disturbances by load centre reactive power resources such as synchronous condensers, switched capacitors and reactors, SVC's, etc.

e) SVC's at Series Capacitor Stations

The reactive power consumption of a highly loaded transmission line during a system disturbance can be modelled as occurring at the line's electrical centre. Therefore, significant additional var reserve may accrue by adding an SVC at that location.

Category D: SERIES COMPENSATION

a) Increasing Existing Series Compensation

The 500 kV lines from the Interior to the Lower Mainland are approximately 50% series compensated. Increasing the level of compensation to as much as 80% would significantly reduce transmission line var consumption thereby improving system voltage stability. Technical issues include higher fault levels and line protection problems[8].

b) New Series Compensation

Some transmission lines peripheral to the Int-LM grid are not series compensated. Series compensating them may strengthen the Interior portion of the Int-LM grid thereby increasing voltage stability reserves.

Category E: LINE SECTIONALIZING

Sectionalizing existing Int-LM transmission lines would reduce the increase in transmission impedance during a single-contingency Int-LM line outage and would, therefore, increase voltage stability limits. Technical issues associated with this category include high line-end series compensation and its associated line protection problems, as well as increased system fault levels. Switching station and potential circuit breaker replacement costs are high while system loss reductions are low.

Category F: AREA TRANSMISSION REINFORCEMENT

Area Transmission systems (i.e. those below 500 kV) that require significant pre-disturbance var suppport may unduly drain reactive power from the bulk supply system during 500 kV line outages. This can result in lower system voltage stability limits than would otherwise be the case. If so, voltage stability limits may be increased by advancing Area Transmission reinforcement ahead of that dictated by Area Transmission Planning requirements.

Category G: MECHANICAL SCHEMES

Technical issues associated with this category include the selection of the appropriate signal (intelligence) to activate each scheme and the time delay before each scheme becomes effective.

a) Switched Shunt Capacitors

Switched shunt capacitors located at the load centre, off during normal

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[8] Protection feasibility can only be confirmed by studying the performance of available relays applied to a power system model which includes the increased series compensation.

system conditions, to be automatically switched on during system disturbances to provide additional voltage support.

b) Switchable Shunt Reactors

Shunt reactors, on during normal system conditions, to be automatically switched off during system disturbances for additional voltage support.

c) Single-Pole Clearing and Reclosing (SPR)

Lines that are equipped with single-pole clearing/reclosing clear only the faulted phase for single-line-to-ground faults (the majority of line disturbances). One automatic attempt is made to reclose the open phase. SPR is more useful for transient stability than for voltage stability because it provides increased synchronizing torque during the open-phase condition.

Category H: REMEDIAL ACTION (NON-STRUCTURAL) SCHEMES

Remedial action schemes (RAS) depend upon post-disturbance control actions to alleviate those system parameters which go outside acceptable ranges. Control logic is invoked when one or more setpoints are exceeded, i.e. a pre-determined selective action is taken based on off-line studies. Some remedial action schemes depend upon remote, as well as local, system data to decide what remedial action to take. Remedial action schemes increase system control complexity and, when they are also dependent upon remote information via communication links, can result in lowered system reliability. For this reason, RAS which are dependent upon the receipt of remote data are not generally valid single-contingency planning options. BC Hydro currently arms RAS only in preparation for second-contingencies[9], i.e. first-contingency reliability is not compromised by activated RAS.

a) Temporary Boost in Series Compensation

After the loss of one of the four Int-LM 500 kV lines, the increase in reactive power consumption on the remaining three 500 kV lines could be mitigated by temporarily boosting the series compensation to 65-80%. Technical issues include high fault levels and line protection problems.

b) OLTC Blocking

After the loss of one of the four Int-LM 500 kV lines, the restoration of the system load and consequent increase in system var consumption could be mitigated by blocking the on-load-tap-changing that is meant to restore load voltages.

c) Auto Phase Shift Control

Automatic control of the Nelway and proposed Selkirk phase shifters could be used to induce a clockwise loopflow around the BC Hydro/BPA Ingledow-Nicola-Selkirk-Boundary-Custer-Ingledow 500/230 kV loop during an Int-LM 500 kV line outage. This would reduce the loading on the remaining Int-LM

[9] The exception being GMS generation shedding which is armed for single-contingency loss of 5L11 or 5L12 until 5L13 comes into service in 1994.

500 kV lines thereby increasing voltage stability limits.

d) Coordinated Automatic Generation Control

After the loss of one of the four Int-LM 500 kV lines, the automatic generation control (AGC) system could be enabled to re-schedule generation away from the weakened portion of the transmission system.

e) Load Dropping

BC Hydro planning criteria specifies no single-contingency loss of firm load or generation. However, second-contingency load and/or generation shedding can be used as an RAS to prevent transient electro-mechanical and voltage instability and consequent cascading outages. BC Hydro has a program underway the ultimate objective of which is to implement an automatic load shedding scheme for multiple-contingency outages.

Category I: NON-CONVENTIONAL INTERIOR TO LOWER MAINLAND TRANSMISSION REINFORCEMENTS

a) High Voltage Direct Current (HVDC) Transmission

HVDC transmission could be used to reinforce the Int-LM 500 kV AC system and/or the Vancouver Island 500 kV AC supply. The principal benefit of HVDC would be its ability to divert power flow away from the weakened portion of the Int-LM 500 kV grid.

b) 765 kV AC Transmission

Ultra High Voltage (UHV) 765 kV AC could be used to reinforce the Int-LM 500 kV AC system and/or the Vancouver Island 500 kV AC supply. The principal benefit of higher AC transmission voltage would be its low real and reactive power consumption and high power transfer capability during parallel 500 kV line outages.

c) High Phase Order Transmission

High Phase Order (HPO) transmission allows increasing the power transfer capability of an existing AC line without having to also increase its operating voltage or right-of-way. Instead of the conventional three phases 120 electrical degrees apart, six phases 60 electrical degrees apart or even twelve phases 30 electrical degrees apart are applied to the existing line at the existing voltage. For lines of comparable power-carrying capacity, the electric and magnetic field intensities at the edge of the right-of-way are considerably lower in the case of the HPO line.

Category J: LOAD DISPLACEMENT

a) Load Centre Generation

An alternative to increasing the Int-LM 500 kV transfer capability is to more fully utilize generators that are already located in the load centre as well as encourage new load centre generation development.

b) Demand Side Management (DSM)

DSM consists of conservation and load management each of which would influence customer use of electricity to reduce Int-LM peak loading.

Conservation is the more efficient use of electricity by all customer groups. Conservation reduces electricity consumption during all hours of the day and therefore can reduce Int-LM transmission requirements.

Load Management re-schedules electricity use by all customer groups to other than the peak load periods and therefore can also reduce Int-LM transmission requirements. Typically, load management does not reduce daily energy consumption.

c) Load Curtailment

Load curtailment reduces electricity consumption by limiting supply only during periods when continued operation of the Int-LM transmission is at risk. The need for load curtailment would be infrequent and generally of short duration.

There are three types of load curtailment:

- Voluntary curtailment by all customer groups at BC Hydro or government agency request.

- Involuntary curtailment through rolling blackouts implemented by BC Hydro and which do not require explicit customer action.

- Contractual arrangements which specify conditions for curtailment.

Table 1 in Appendix 2 summarizes all of the options. This table gives an option reference number, project category, description, and judgemental ranking. The technical and economic factors, including option lead times, are also shown, as well as the various outstanding activities needed to fully assess each option's viability. The final column shows the class assignments which are discussed in Sections 6 and 7 below. For Class C options, the "B/F (Bring Forward) When" column shows the conditions under which an option's classification might be reviewed.

6. CLASS A AND CLASS B OPTIONS

6.1 General

Those options ranked six to nine which were able to meet the multiple objectives of technical effectiveness, economy, proven reliable technology, and system compatibility, were designated as 'Class A'. Class A options are recommended for consideration when developing the alternate long-term plans in [2]. Those options which came close to meeting the objectives above were designated 'Class B' options.

The increases in Int-LM power transfer capability[10] provided by the Class A and Class B options, as well as selected class C and D options, are shown in Figure 2 in Appendix 1 and Table 2 in Appendix 2. The increase in single-contingency transfer capability is shown for both maximum Peace and maximum Columbia generation. Each option's net unit cost ($/kW/a) of Int-LM reinforcement was also calculated. Economic analysis results, assuming an 8% discount rate, are shown in Figure 3 in Appendix 1 and Table 3 in Appendix 2. The results of a sensitivity study that assumed a 5% discount rate are shown in Figure 4 in Appendix 1 and Table 4 in Appendix 2.

6.2 Study Results

Option 1: Kelly Lake to Cheekye 500 kV No. 2 (5L46) (Category A)

A detailed description of Circuit 5L46 series compensated transmission line is included in [3]. Figure 5 in Appendix 1 shows the proposed route for 5L46. The earliest in-service date for this circuit would be 1996. This line would parallel the most heavily loaded Int-LM 500 kV line (5L42) and would increase the voltage and transient stability and thermal capacities of the Peace side of the Int-LM grid. It would also improve the security of the Vancouver Island 500 kV Supply and reduce system losses. This circuit would increase to a lesser extent the capacity limit on the Columbia side of the Int-LM grid. Lead time for this option is 6 years.

Circuit 5L46:

- would increase Peace and Columbia Int-LM transfer capabilities by 533 MW and 359 MW, respectively;
- would have a direct cost of approximately $150 million;
- would have approximate Peace and Columbia unit costs of $9.6/kW/a and $14.3/kW/a, respectively;
- is a Class A option.

[10] Based on the 1994/95 basecase powerflow.

Option 2: JVC/LDC at Major Generating Stations and Synchronous Condensers (Category B)

Some form of JVC and/or LDC facility now exists at GMS, Peace Canyon, Mica, Kootenay Canal, Burrard, and VIT. However, for a variety of technical reasons these are not now in use except at GMS and Burrard. QV studies have shown that JVC/LDC enabled at Mica and installed at Bridge River would be effective in increasing both Peace and Columbia voltage stability limits. Preliminary information indicates that all of the existing facilities could be put to use at little cost and in a short period of time. Unresolved technical issues include excitation, field current, and terminal voltage limitations.

JVC/LDC enabled at Mica and installed at Bridge River:

- would increase Peace and Columbia Int-LM transfer capabilities by 217 MW and 237 MW, respectively;
- would have a direct cost of approximately $450,000;
- would have a unit cost of $0.23/kW/a;
- is a Class B option because of unresolved technical issues.

Option 3: LM/VI Shunt Capacitors for Pre-outage Voltage Support (Category C)

BC Hydro has an on-going program of shunt capacitor additions to ensure that the continuing LM/VI load growth, with its associated growth in var demand, does not deplete system dynamic var reserve in an effort to maintain nominal operating voltages. Under this program, approximately 1100 Mvar of shunt capacitors, at an estimated direct cost of $18 million ($1990), are scheduled to be installed in the Lower Mainland and Vancouver Island from October 1989 to October 1994.

This is a Class A option which is an on-going part of normal system transmission reinforcement.

Option 4: Static Var Compensators (SVC) at 500/230 kV Substations (Category C)

The effectiveness of an SVC depends upon its location as well as on its rating. Locations that have been considered include the Nicola, Kelly Lake, Cheekye, Malaspina, Dunsmuir, Meridian and Ingledow 230 kV buses. Cheekye was rejected in favour of Malaspina because Cheekye lacks 500/230 kV transformation. Meridian was rejected because Ingledow is the main load centre bus and, therefore, a logical location for an SVC (two SVC's located only a few kilometres apart could be difficult to coordinate). Dunsmuir was rejected because an SVC is already scheduled to go into service there in 1993.

Investigations have found that SVC's located at Nicola, Kelly Lake, Malaspina, and/or Ingledow are feasible and effective. QV studies have assumed that the Ingledow SVC capacitive output is limited to 200 Mvar to comply with System Planning Criteria with regard to the loss of the largest var source at the load centre. At other locations a 300 Mvar capacitive capability was assumed.

Lead time per SVC location is estimated to be 3 to 4 years.

SVC's at 500 kV Substations Summary (firm/non-firm)[11]:

LOCATION	SIZE(MVAR)	COST(K$)	DELTA-MW	$/kW/A	CLASS
Ingledow	+200/-100	19000	378/440	6.9/ 5.9	A
Kelly Lake	+300/-150	26400	235/304	14.7/11.4	A
Nicola	+300/-150	26400	309/310	11.2/11.2	A
Malaspina	+300/-150	26400	275/371	12.6/ 9.4	A

Option 5: Nicola to Meridian 500 kV No. 2 (5L83) (Category A)

As shown in Figure 6 in Appendix 2, Circuit 5L83 series compensated line would parallel Circuit 5L82 and would increase the voltage and transient stability and thermal capacities of the Columbia side of the Int-LM 500 kV grid. It would also reduce system losses. Lead time for this option is estimated to be about 9 years.

Circuit 5L83:

- would increase Peace and Columbia Int-LM transfer capabilities by 569 MW and 1007 MW, respectively;
- would have a direct cost of approximately $198 million;
- would have approximately Peace and Columbia net pay backs of $6.9/kW/a and $3.9/kW/a;
- is a Class A option.

Note from Figure 2(a) that both 5L46 and 5L83 must be brought into service in order to realize the increase in firm Int-LM transfer capability that each line provides individually in increased non-firm Int-LM transfer capability.

The combined option of adding both 5L46 and 5L83:

- would increase Peace and Columbia Int-LM transfer capabilities by 983 MW and 995 MW, respectively;
- would have a direct cost of approximately $348 million;
- would have approximately Peace and Columbia unit costs of $6.4/kW/a and $6.3/kW/a.

Option 6: Operation of 2L2 at 360 kV (Category A)

Circuit 2L2 between Bridge River G.S. and Cheekye Substation is constructed to 360 kV standards but is currently operated for Area Transmission purposes at 230 kV. Optimizing the operation of this circuit would include re-terminating its north end at the Bridge River 360 kV bus, re-terminating its south end at a new Cheekye Substation 360 kV bus, and adding a Cheekye 360/230 kV transformer. The Pemberton and Rainbow loads would need to be served from Circuit 2L1. As well, a new Cheekye 230/500

[11] "firm" and "non-firm" transfer capabilities refer to the smaller and the larger of the two voltage stability transfer capabilities, respectively, discussed in this section.

kV transformer would be included to strengthen the Cheekye 500 kV bus for 5L42 or 5L45 outages. If 2L1 is dismantled to accomodate 5L46 this option will become much more expensive and probably be precluded as a future option. Operating 2L2 at 360 kV would reduce system losses and would increase the voltage stability limit on the Peace side of the Int-LM 500 kV grid. Lead time for this option is 3 years.

Option 7: Series Capacitors on Circuit 2L2(360 kV) (Category D)

This option carries Option 6 a step further by 50% series compensating 2L2(360 kV) at the old Tisdall series capacitor site. Lead time for this option is 3 years.

The combination of Option 6 and Option 7 (Bridge River Upgrade) is shown in Figure 7; Appendix 1.

Series compensating 2L2 and operating it at 360 kV:

- would increase Peace and Columbia Int-LM transfer capabilities by 128 MW and 93 MW, respectively;
- would have a direct cost of approximately $25 million;
- would have approximate Peace and Columbia unit costs of $16/kW/a and $22/kW/a, respectively;
- is a Class B option because of the relatively small increase in Int-LM transfer capability that it provides.

Option 8: Permanent Increase in Series Compensation of Int-LM Lines to 65% (Category D)

Increasing the series compensation on 5L41 and 5L42 to 65% would reduce both pre- and post-outage reactive power consumption and thereby increase voltage and transient stability limits in the Peace side of the Int-LM grid. Increasing the series compensation on 5L81 and 5L82 to 65% would do the same for the Columbia side of the grid. This option was studied by Powertech and is reported in [4]. There are technical concerns about protecting transmission lines which are series compensated much beyond 50%; however, for the purposes of this report 65% series compensation is assumed feasible. Lead time is 5 years.

Permanent Increase in Series Compensation of 5L41/42/81/82 to 65%:

- would increase Peace and Columbia Int-LM transfer capabilities by 460 MW and 400 MW, respectively;
- would have a direct cost of approximately $28 million;
- would have approximate Peace and Columbia unit costs of $10.7/kW/a and $12.3/kW/a, respectively;
- is a Class A option.

Option 11: Switching Station at Ruby Creek (Category E)

A switching station located at Ruby Creek (see Figure 8; Appendix 1) would sectionalize the Int-LM grid in the eastern Fraser Valley by looping in and terminating 5L41, 5L81, and 5L82. By sectionalizing these circuits, the increase in Int-LM line impedance after a single-contingency line outage would be significantly less than is experienced in the existing system, i.e. the effect would be to lose half a line rather than a whole

line. This arrangement would significantly increase the voltage and transient stability (but not thermal) limits on the Columbia side of the Int-LM grid. It would not significantly increase Peace side voltage stability limits. Technical issues associated with this option include having to protect possibly overcompensated lines (5L81 and 5L82 at American Creek, 5L41 at Chapmans), increased system fault levels, capacitor bank protection, and interruption of non-zero currents, etc. Lead time is 5 years.

A Switching Station at Ruby Creek:

- would increase Peace and Columbia Int-LM transfer capabilities by 67 MW and 930 MW, respectively;
- would have a direct cost of approximately $39 million;
- would have approximate Peace and Columbia unit costs of $75.3/kW/a and $5.4/kW/a, respectively;
- is a Class A option.

Option 13: Demand Side Management (Catagory J)

BC Hydro's Power Smart program is a DSM initiative. The forecast of reduced electricity demand due to Power Smart has been included in the technical studies discussed in this report. DSM is a Class A option which is now underway.

Option 20: New 50% Series Compensation on 5L87 (Category D)

Fifty-percent series compensation of 5L87 (NIC-KLY) would reduce the electrical distance between the sending ends of the Peace and Columbia sides of the Int-LM grid by half. This would better balance Int-LM flows, increase the overall voltage stability limit of the Int-LM grid, and help a reinforcement on one side of the grid to also strengthen the other side. Technical issues associated with series compensating 5L87 include the effect on the Nicola and Kelly Lake fault levels and the future of the capacitor station if Hat Creek is developed. Lead time would be 4 years at a direct cost of approximately $11 million.

This is a Class A option because studies done for [2] have shown that series compensating 5L87 50% provides significant long-term benefits of relief from Int-LM transmission thermal capacity limitations.

7. CLASS C AND CLASS D OPTIONS

7.1 General

Those options shown in Table 1 in Appendix 2 that were unable to meet the multiple objectives of effectiveness, economy, proven technical feasibility, and system compatability were designated 'Class C' or 'Class D' options. Class C options are those whose status may change within a reasonable period of time due to changing system conditions, economics, technology advances, new study information, etc. and whose status should be periodically reviewed. Table 1 in Appendix 2 provides a column for Class C options showing the change which would justify a further review. Class D options are those whose status is unlikely to change within a reasonable period of time and therefore are not considered valid planning

options. Some Class D options, however, may be applied for increasing operating flexibility.

7.2 Discussion

Option 9: Nicola to Ingledow 500 kV No.2 (Category A)

This circuit would be an alternative to 5L83 (Option 5) for reinforcing the Columbia side of the Int-LM grid. A potential route is shown in Figure 10 in Appendix 1 which could be used if the Kelly Lake-Meridian 500 kV line No.1 (Option 16) was used instead of 5L46 to reinforce the Peace side of the grid. Corridor access for this line would be more difficult than for 5L83 and the line would have an earliest in-service date beyond the year 2000. The direct cost for this option would be $167 million plus the cost associated with displacing 2L75/76/77/78.

This is a Class C option which may be considered as a reinforcement for the Columbia side of the Int-LM grid if Kelly Lake to Meridian is built instead of 5L46.

Option 10: LDC at Small LM/VI Plants (Category B)

The relatively small LM/VI generating stations do not have LDC facilities to control their high voltage buses. Installation of LDC facilities at these plants is a Class D option because it is assumed that as the load centre voltage collapses the load centre generators will go to maximum var output, even without the LDC added.

Option 12: Burrard Units 5 and 6 Synchronous Condenser Operation (Category C)

Burrard Thermal units 1-4 have synchronous condenser capability but units 5 and 6 do not. The conversion to synchronous condenser operating mode entails uncoupling of the turbine-generator shaft and use of a pony motor for start-up and synchronizing the generator. Converting the last two Burrard units to synchronous condenser capability would extend the transfer capability of the Int-LM system approximately two years. However, Operations has requested that Burrard units 5 and 6 be reserved as generators to firm up the existing Meridian 500/230 kV transformation. The various roles that Burrard Thermal will play in future BC Hydro operations is now under comprehensive review. This is a Class C option pending the outcome of that review.

Options 14 and 15: Area Transmission Upgrades (Category F)

Advancing Area Transmission upgrades on Vancouver Island (Option 14) and in the Lower Mainland (Option 15) to increase Int-LM voltage stability limits was studied by Powertech and documented in [4]. In summary, both are Class C options since Powertech reports no significant increases in Int-LM voltage stability limits. Periodic reviews should be made to ensure no pockets of Area Transmission weakness are unduly draining reactive power from the bulk supply system during critical outages.

Option 16: Kelly Lake to Meridian 500 kV No.1 (Category A)

This circuit is shown in Figure 9 Appendix 1 and it would be an

alternative to 5L46 (Option 1). However, the line would traverse a much longer route and would cost significantly more. Corridor access for this line would be difficult. The line would have an earliest in-service date beyond the year 2000. The direct cost for this line would be $219 million.

This is a Class C option which may be considered as a reinforcement for the Peace side of the Int-LM grid after 5L46.

Option 17: HVDC Runback (Category H)

Var consumption in the Lower Mainland, and therefore Int-LM voltage stability limits, are directly related to the HVDC transfer to Vancouver Island. Running back the HVDC during an Int-LM 500 kV outage to release dynamic vars is a Class D option because it is an RAS and because there is no assurance that, at the time of a critical outage, there will be as much runback available as assumed in the planning simulations. Also, for some Int-LM 500 kV outages, runup may be preferred to runback. HVDC runback may be considered for increasing operating flexibility.

Option 18: Temporary Boost in Series Compensation (Category H)

Selective temporary boosting of the series capacitor compensation on the Int-LM lines represents the application of one of a number of emerging technologies collectively referred to as FACTS[12]. It has been studied by Powertech for use on 5L41, 5L42, 5L81 and 5L82 (see [4]).

The simplest type of temporary boost scheme would be to provide an additional normally bypassed capacitor bank, on a separate platform, at each Int-LM series capacitor station. The purpose would be to provide a substantial increase in Int-LM transfer capability by increasing Int-LM series compensation by 15% (to approximately 65% total) when a critical line outage occurs. This scheme would be similar to GMS generation shedding which relies on communications but is considered acceptable only for second or multiple-contingency disturbances. This option would not rely solely on information gathered at the series capacitor site as the GMS braking resistor scheme does, nor would it have a local backup as the 500 kV line protection schemes do. Therefore, because this option is a remedial action scheme prone to failure, its use for single contingencies, and hence as a planning option, is considered unacceptable at this time. However, studies indicate that this scheme could provide a considerable amount of post-line outage power transfer capability and, therefore, it should be further investigated as a way of relieving operating constraints.

Powertech also studied temporarily boosting Int-LM series compensation to 80%; however, this option is not pursued here because of considerable uncertainty regarding protection feasibility.

Temporary Boost in Series Compensation of 5L41/42/81/82 to 65%:

- would increase Peace and Columbia Int-LM transfer capabilities by 760 MW and 640 MW, respectively;
- would have a direct cost of approximately $29 million;

[12] Flexible Alternating Current Transmission

- would have approximate Peace and Columbia unit costs of $4.3/kW/a and 5.1/kW/a;
- is a Class C option.

Option 19: Series Compensation of BPA 500 kV Lines (Category D)

The 500 kV ties to BPA have limited strength when supporting Lower Mainland bus voltages during critical Int-LM outages. Much of the limitation lies between BPA's Monroe and Custer Substations. This option proposes to add 50% series compensation to the two Monroe-Custer 500 kV lines to strengthen both the Custer and Ingledow 500 kV buses. Benefits would accrue to both BC Hydro and BPA. This is a Class C option since it is uncertain how long it would take to develop interutility cost sharing and operating agreements for such a project. It should be reviewed as part of any joint BC Hydro/BPA planning for voltage stability.

Option 21: LM/VI Switched Shunt Capacitors for Outage Voltage Support (Category G)

Some portion of the additional vars that are needed to support LM/VI load centre bus voltages during critical Int-LM line outages could be supplied by load bus switched shunt capacitors which are kept off line (i.e. held in reserve) prior to a critical outage. As such, switched shunt capacitors augment SVC's and synchronous condensers in providing load centre voltage support. An unresolved technical issue is which change in system state should be used to switch the shunt capacitor banks, i.e. the opening of an Int-LM 500 kV line, a sudden drop in load centre voltage, etc. The answer requires more information about the dynamic characteristic of BC Hydro's load. This is a Class C option until that information becomes available.

Option 22: Area Transmission-Level SVC's (Category C)

The effect of adding a +150/-75 Mvar SVC at Kidd #2 Substation and a +200/-100 Mvar SVC at Walters Substation would be similar to adding a +350/-175 Mvar SVC at Ingledow. However, the cost will be more due to the duplication of some substation and control equipment. This option was studied by Powertech and is reported in [4].

Area Transmission Level SVC's:

- would increase Peace and Columbia Int-LM transfer capabilities by 600 MW and 540 MW, respectively;
- would have a direct cost of approximately $34 million;
- would have approximate Peace and Columbia unit costs of $7.3/kW/a and $8.1/kW/a;
- is a Class C option which should be reviewed when optimizing any new SVC for the Lower Mainland.

Option 23: Automatic Generation Control (AGC) Runback (Category H)

Coordinated adjustment of Peace and Columbia generation is the principal preventive measure now taken by BC Hydro to assure single-contingency voltage stability. Powertech studied and reported in [4] increasing the Int-LM transfer capability by making this a remedial (rather than preventive) action to be carried out automatically by the AGC system.

This is a Class D option because it is an RAS and because:

- there is no assurance that at the time of the outage there will be enough resource flexibility to accommodate the AGC remedial action;

- there is no assurance until the BC Hydro dynamic load characteristic is better defined that the AGC action is fast enough to forestall voltage collapse.

Automatic coordinated adjustment of Peace and Columbia generation may be considered for increasing operating flexibility.

Option 24: Kelly Lake to Campbell River Area 500 kV Transmission Line (5L26) (Category A)

Circuit 5L26 would be an alternative to 5L46 (Option 1) because it would increase the Int-LM transfer capability as well as reinforce the supply to Vancouver Island. However, 5L26 would be significantly longer and more expensive and would traverse more difficult terrain than would 5L46. As well, 5L26 would not make use of any existing right-of-way as 5L46 is proposed to do. The principal advantage of 5L26 is that it could also be used to integrate the output from any Homathko development. This is a Class C option because of its high cost, the relatively low increase in Int-LM transfer capability that it would provide, and its anticipated earliest in service date beyond the year 2000. This option should be reviewed as part of any Homathko integration study.

Option 25: Permanent Increase in Series Compensation of Int-LM Lines to 80% (Category D)

Increasing the series compensation on 5L41 and 5L42 to 80% would reduce both pre- and post-outage reactive power consumption thereby increasing voltage and transient stability limits in the Peace side of the Int-LM grid. Increasing the series compensation on 5L81 and 5L82 to 80% would do the same for the Columbia side of the grid. This option was studied by Powertech and is reported in [4].

Permanent Increase in Series Compensation of 5L41/42/81/82 to 80%

- would increase Peace and Columbia Int-LM transfer capabilities by 860 MW and 720 MW, respectively;
- would have a direct cost of approximately $45 million;
- would have approximate Peace and Columbia unit costs of $17.7/kW/a and $21.1/kW/a;
- is a Class C option until the technical feasibility of protecting such highly compensated lines is demonstrated.

Option 26: Lower Mainland Coordinated Var Control (Category C)

There is currently no automatic pre- or post-disturbance coordination of switched shunt capacitors, switched shunt reactors, and dynamic var sources in the Lower Mainland. Such coordination could increase Int-LM transfer capability through optimal pre- and post-disturbance var dispatch. This option would require a complex control scheme which would have to balance Area and System reactive power requirements. This is a Class C option until the BC Hydro dynamic load characteristic is better

defined and further investigation of the technical viability of such a scheme is carried out.

Option 27: On Load Tap Change (OLTC) Blocking (Category H)

A major factor in the restoration of system load after a major outage is OLTC transformer tapping to re-establish pre-outage load bus voltages. This action reduces voltage stability margins and increases the risk of voltage collapse. Reference [5] describes one utility which used selective blocking of bulk supply substation OLTC transformer taps as a temporary measure for increasing voltage stability margins until new transmission lines could be installed. This is a Class D option because it is a RAS and because its use could lead to an extended period of low system voltage during which motors may burnout and/or trip off line while the system suffers potential dynamic voltage instability. As well, this is not a feasible option where distribution transformers are OLTC, as is the case in BC Hydro.

Option 28: Interior to Lower Mainland HVDC Transmission (Category I)

HVDC is currently used to transmit power from the Lower Mainland to Vancouver Island. A useful feature of this system has been its ability to influence the power flow over the parallel AC ties during normal and emergency conditions. A major cost component of HVDC transmission is the converter stations which are required at each end of the line. This is a Class C option because of its probable high cost and long lead time needed for engineering and design. It should be reviewed as an option as the cost of this technology comes down.

Option 29: Interior to Lower Mainland 765 kV Transmission (Category I)

The power transfer capability of a 765 kV (UHV) transmission line is approximately 50% more than for a similarly conductored 500 kV line. The real and reactive powers consumed by a 765 kV line are less than half that consumed by a similarly conductored 500 kV line. This is a Class C option because of its probable high cost and long lead time needed for engineering and design. It should be reviewed as a reinforcement option when corridor access into the Lower Mainland becomes unduly restrictive.

Option 30: Bulk Transmission System Overvoltage Operation (Category C)

Raising the operating voltage on the 500 kV system 5-10% would reduce the pre- and post-outage reactive power losses which in turn would increase the Int-LM transfer limit. This is a Class D option because critical overvoltages already exist in parts of the Int-LM 500 kV grid during off-peak system loads and because there is no 500/230 kV OLTC capability with which to re-adjust the taps as the system load cycles.

Option 31: Operate Southern Vancouver Island Transmission at 500 kV (Category A)

The two 500 kV-constructed transmission lines between Dunsmuir and Pike Lake (2L123/126/128/170) are now operated at 230 kV. Scheduled conversion to 500 kV operation will be determined by southern Vancouver Island load growth. Advancing this conversion for voltage stability would require adding 500/230 kV transformers at Sahtlam and Pike Lake substations. This

is a Class D option because QV studies have found the conversion yields only a minor increase in Int-LM transfer capability.

Option 32: Mid-line SVC's (Category C)

Interior to Lower Mainland series capacitor stations may be effective locations for new SVC's. However, this is a Class C option until the technical feasibility of operating and protecting mid-line series capacitor/SVC combinations is proven.

Option 33: Automatic Remedial Phase-Shifter Control (Category H)

After the outage of one of the Int-LM 500 kV lines, automatic control of the Nelway and proposed Selkirk phase shifters could be used to divert some of the Int-LM flow to BC Hydro's eastern ties to BPA for eventual return to Ingledow via BPA's Custer Substation. This option was studied by Powertech who reported their results in [4]. This is a Class D option because it is an RAS and because:

- there is no assurance that, at the time of a critical outage, there will be as much phase angle angle adjustment range available as assumed in the planning simulations;

- until BC Hydro's dynamic load characteristic is better defined it will not be known if the tap changing will be fast enough to forestall voltage collapse; and

- it requires acceptance by BPA.

Automatic control of phase shifters may be considered for increasing operating flexibility.

Option 34: Kelly Lake-Bridge River-Lower Mainland High Phase-Order (HPO) Transmission (Category A)

Powertech investigated the increase in Int-LM transfer capability by replacing 2L90/91 (KLY-BRT), 3L2 (BRT-ROS), and 2L75/76/77/78 (ROS-ING), with a six-phase 50% series compensated 208 kV[13] line from Kelly Lake to Ingledow via Bridge River and Rosedale. They also investigated the increase for a new six phase 208 kV line from Kelly Lake to Cheekye via Bridge River and reported their results in [4].

360 kV HPO Transmission:

- would increase Peace and Columbia Int-LM transfer capabilities by 697 MW and 221 MW, respectively;
- would have a direct cost of approximately $164 million;
- would have approximate Peace and Columbia unit costs of $17.5/kW/a and $55/kW/a;
- is a Class D option because of its high cost, and because the Bridge River to Ingledow via Rosedale right-of-way has been considered for one or more future 500 kV lines (Option 9).

[13] line-to-neutral voltage

Option 35: Burrard Thermal Generation (Category J)

Burrard Thermal is assumed to have essentially zero dependable winter capacity because of an uncertain and expensive winter fuel supply. Nevertheless, running Burrard at some, or all, of its 900 MW capacity over the heavy/peak load hours would offload the Int-LM grid by a similar amount. Concerns with this option, beyond just fuel supply, include the potential for community opposition, rising maintenance costs, and the long-term future of the plant. Lead time to arrange a long-term gas contract for Burrard would be approximately 4 years.

Units 5 and 6 can be run at 40 MW minimum output for voltage support, if necessary, and if fuel supplies are available. However, the contract cost of operating units 5 and 6 at minimum output in order to make their dynamic var capabilities available to the system approximately equals the annualized cost of an equivalently sized SVC.

This is a Class C option which should be reviewed if gas contract prices fall or as a temporary measure until permanent Int-LM reinforcements can be added.

Option 36: Shunt Reactor Tripping (Category C)

Tripping the fixed and switchable reactors at Kelly Lake and Nicola for an Int-LM outage would release dynamic vars and increase the Int-LM transfer capability. This is a Class D option because there is no assurance that, at the time of the outage, there will be as many shunt reactors available for tripping as assumed in planning simulations. Shunt reactor tripping may be considered for increasing operating flexibility.

Option 37: Load Shedding (Category H)

The facility to automatically drop load for single-contingency Int-LM 500 kV outages would allow an increase in Int-LM (non-firm) transfer capability. Technical concerns include the complexity and security of such a remedial action scheme, what change in system state should be used to initiate shedding, how much to shed, and the system dynamic load characteristic.

This is a Class C option until BC Hydro criteria changes regarding single-contingency supply security to its firm loads.

8. OTHER CONSIDERATIONS

System second-contingency performance, and the relative outage rates of alternative transmission elements, were not included in the economic comparisons in Section 6. However, they are important factors when assessing system reinforcement options which have similar first-contingency costs and benefits.

8.1 Second-contingency Comparisons

Second-contingency voltage stability and line loading analyses were done to further differentiate the relative merits of the transmission and non-transmission reinforcement options. More second-contingency Int-LM

transfer capability[14] means:

- more opportunity to schedule maintenance outages;
- more opportunity to serve off-peak electricity trade initiatives;
- more system strength to survive simultaneous forced outages without loss of load or generation; and
- less reliance on complex remedial action schemes which, if used to excess, may actually reduce system reliability.

Appendix 3 shows that 5L46 provides more second-contingency voltage stability margin and less thermal overload risk[15] than does either the Ingledow SVC or the 65% Series Compensation options.

8.2 Reliability Comparisons

It is not practical at this time for BC Hydro to carry out meaningful probability-based system transmission planning. However, an insight about how well each alternative reinforcement technology can improve system reliability can be found in its outage record.

Appendix 4 provides a reliability comparison of 500 kV transmission lines, series capacitor banks, static var compensators, and synchronous condensers. The conclusion is that the forced outage rate of a 200-300 km transmission line is approximately 10 hours per year compared to 160 to 200 hours per year for the non-transmission options.

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[14] without RAS

[15] most notably the double outage of 5L42 and 5L45

9. CONCLUSIONS

1. Class A options:

   a) Kelly Lake to Cheekye 500 kV Transmission Line No.2 (5L46)
   b) LM/VI Shunt Capacitors for Pre-outage Voltage Support
   c) Static Var Compensators at 500/230 kV Substations
   d) Nicola to Meridian 500 kV Transmission Line No.2 (5L83)
   e) Permanent Increase to 65% Series Compensation of Int-LM Lines
   f) Switching Station at Ruby Creek
   g) Demand Side Management
   h) Adding 50% Series Compensation to Circuit 5L87

2. Class B options:

   a) JVC/LDC Facilities at Major Plants
   b) Bridge River Upgrade to 360 kV

3. Class C options:

   a) Nicola to Ingledow 500 kV Transmission Line No.2
   b) Burrard Units 5 and 6 Synchronous Condenser Capability
   c) Area Transmission Upgrades
   d) Kelly Lake to Meridian 500 kV Transmission Line No.1
   e) Temporary Boost to 65% Series Compensation of Int-LM Lines
   f) Series Compensation of BPA 500 kV Lines
   g) LM/VI Switched Shunt Capacitors for Outage Voltage Support
   h) Area Transmission-level Static Var Compensators
   i) Kelly Lake to Campbell River 500 kV Transmission Line No.1
   j) Permanent Increase to 80% Series Compensation of Int-LM Lines
   k) Lower Mainland Coordinated Var Control
   l) Int-LM HVDC Transmission
   m) Int-LM 765 kV Transmission
   n) Mid-line Static Var Compensators
   o) Burrard Generation
   p) Single-Contingency Outage Load Tripping

4. Class D options:

   a) JVC/LDC Facilities at Small LM/VI Plants
   b) HVDC Runback
   c) Automatic Generation Control Runback
   d) On Load Tap Change Blocking
   e) Bulk Transmission System Overvoltage Operation
   f) Southern Vancouver Island Transmission at 500 kV
   g) Automatic Remedial Phase-Shifter Control
   h) KLY-BRT-Lower Mainland High Phase Order Transmission
   i) Shunt Reactor Tripping

5. Circuit 5L46 would provide greater second-contingency Int-LM transfer capability than would either the SVC or the series compensation options.

6. Transmission line options are significantly more reliable than non-transmission options.

10. RECOMMENDATIONS

10.1 General

1. Class A options be considered in the long-term plans in [2].

2. Class B options be developed to provide additional flexibility to plans in [2].

3. Class C options be periodically reviewed for status changes.

4. Class D options not be considered planning options but some could be used to increase operating flexibility.

10.2 Specific

1. A strategy should be adopted to plan for the use of Circuits 5L46 (Option 1) and 5L83 (Option 5) together to reinforce the Int-LM transmission system so as to maximize the increase in Int-LM transfer capability at minimum net unit cost.

2. Initiate investigation of 5L83 route access options into Meridian Substation.

3. Investigate the technical feasibility of protecting Int-LM 500 kV transmission lines that are series compensated beyond 50%.

4. A study be done to resolve the outstanding technical issues associated with the implementation of JVC/LDC at major plants.

5. A study and field test program should be developed to determine the dynamic and steady-state characteristics of B.C. Hydro's Lower Mainland and Vancouver Island load.

6. A study be done to assess the practicality of using Option 17 (HVDC Runback), Option 18 (Temporary Boost of Int-LM Series Compensation to 65%), and Option 23 (AGC Runback) to increase system operating flexibility.

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APPENDIX 1

FIGURES

FIGURES

1. 1990/91 B.C. HYDRO MAJOR TRANSMISSION SYSTEM
2. INT-LM REINFORCEMENT OPTIONS - VOLTAGE STABILITY ANALYSIS
3. INT-LM REINFORCEMENT OPTIONS - ECONOMIC ANALYSIS (@ 8% DISCOUNT RATE)
4. INT-LM REINFORCEMENT OPTIONS - ECONOMIC ANALYSIS (@ 5% DISCOUNT RATE)
5. KELLY LAKE - CHEEKYE #2 500 kV TRANSMISSION LINE
6. NICOLA - MERIDIAN #2 500 kV TRANSMISSION LINE
7. BRIDGE RIVER SYSTEM REINFORCEMENT
8. 500 kV SWITCHING STATION NEAR RUBY CREEK
9. KELLY LAKE - MERIDIAN #2 500 kV TRANSMISSION LINE
10. NICOLA - INGLEDOW #2 500 kV TRANSMISSION LINE

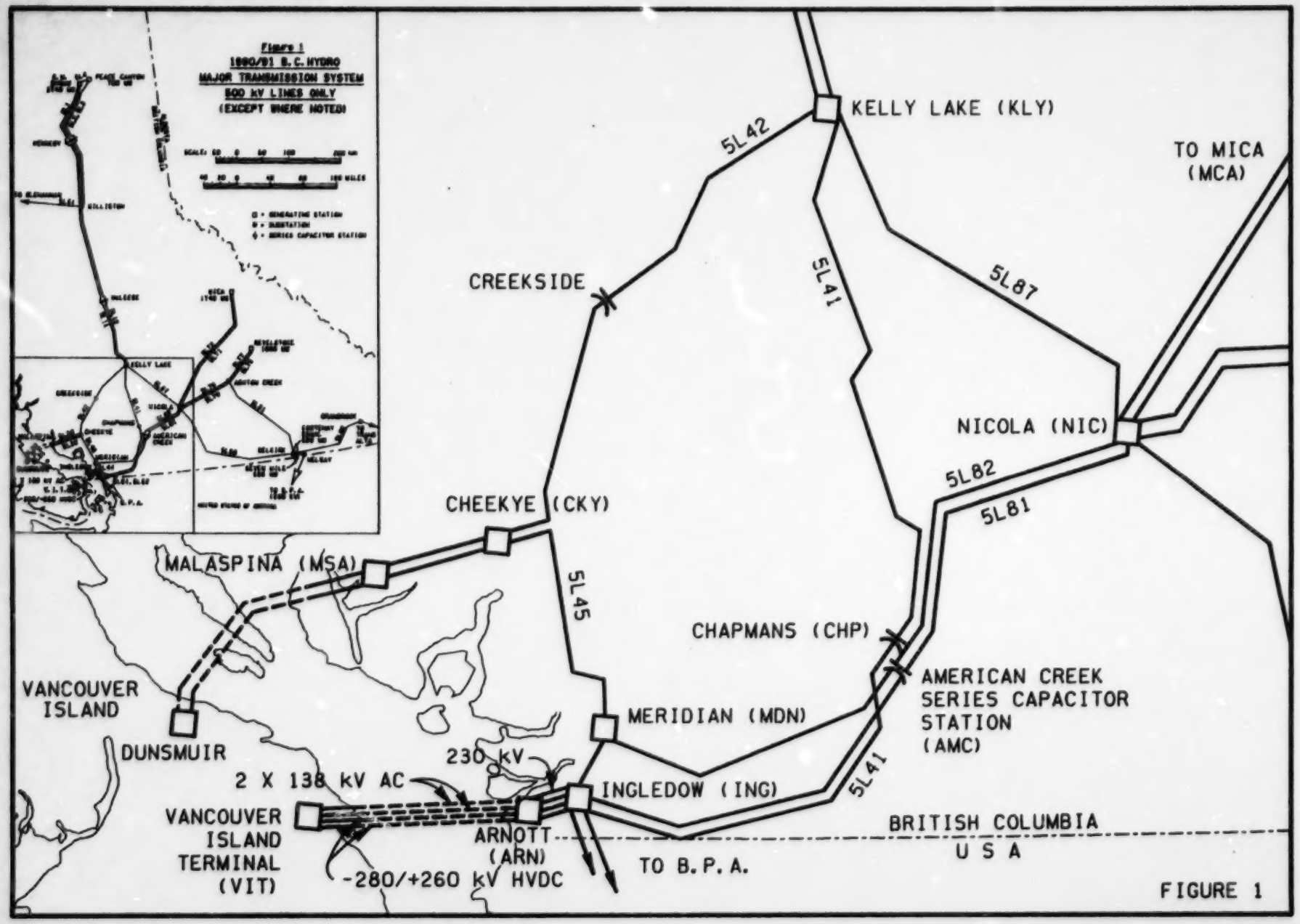


Figure 1
1980/81 B.C. HYDRO
MAJOR TRANSMISSION SYSTEM
500 kV LINES ONLY
(EXCEPT WHERE NOTED)
KELLY LAKE (KLY)
5L42
TO MICA
(MCA)
5L87
5L41
CREEKSIDE
NICOLA (NIC)
5L82
5L81
CHEEKYE (CKY)
MALASPINA (MSA)
5L45
CHAPMANS (CHP)
AMERICAN CREEK
SERIES CAPACITOR
STATION
(AMC)
VANCOUVER
ISLAND
MERIDIAN (MDN)
DUNSMUIR
230 kV
2 X 138 kV AC
INGLEDOW (ING)
5L41
VANCOUVER
ISLAND
TERMINAL
(VIT)
ARNOTT
(ARN)
BRITISH COLUMBIA
U S A
TO B.P.A.
-280/+260 kV HVDC

FIGURE 1

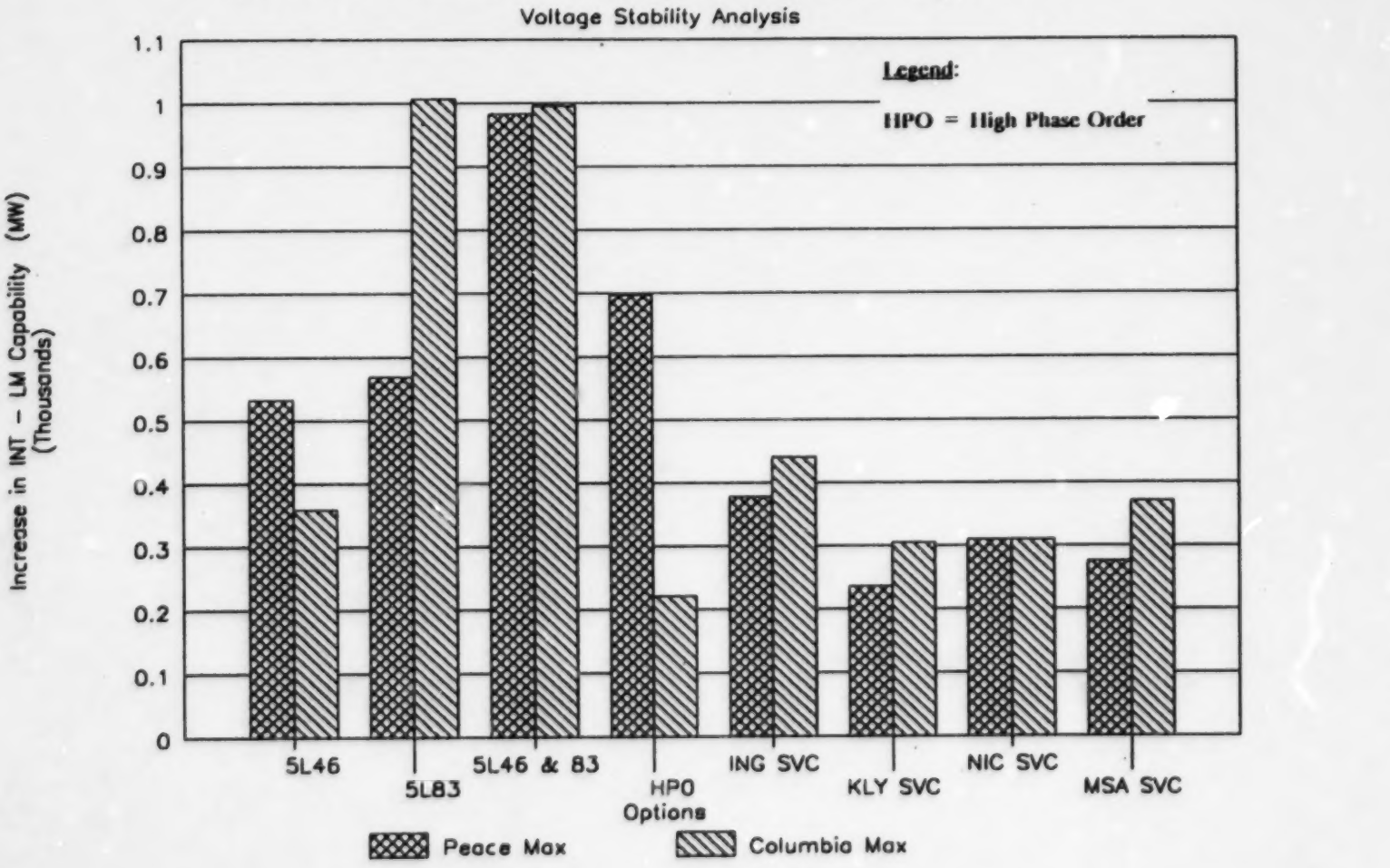
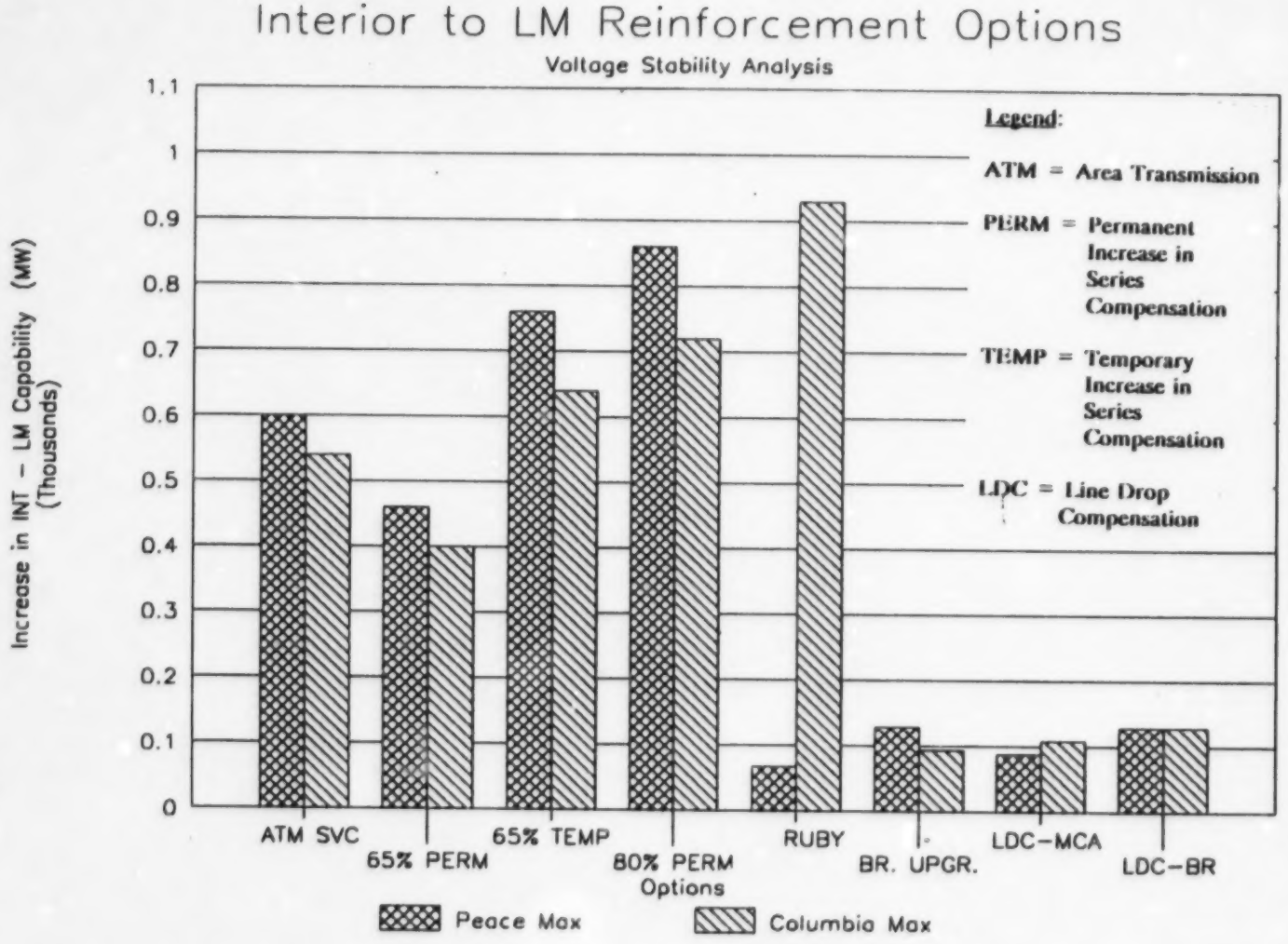

Interior to LM Reinforcement Options
Voltage Stability Analysis
Legend:
HPO = High Phase Order
Increase in INT – LM Capability (MW)
(Thousands)
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
5L46
5L83
5L46 & 83
HPO
Options
ING SVC
KLY SVC
NIC SVC
MSA SVC
Peace Max
Columbia Max
04-Mar-91

FIGURE 2(a)



04-Mar-91

FIGURE 2(b)

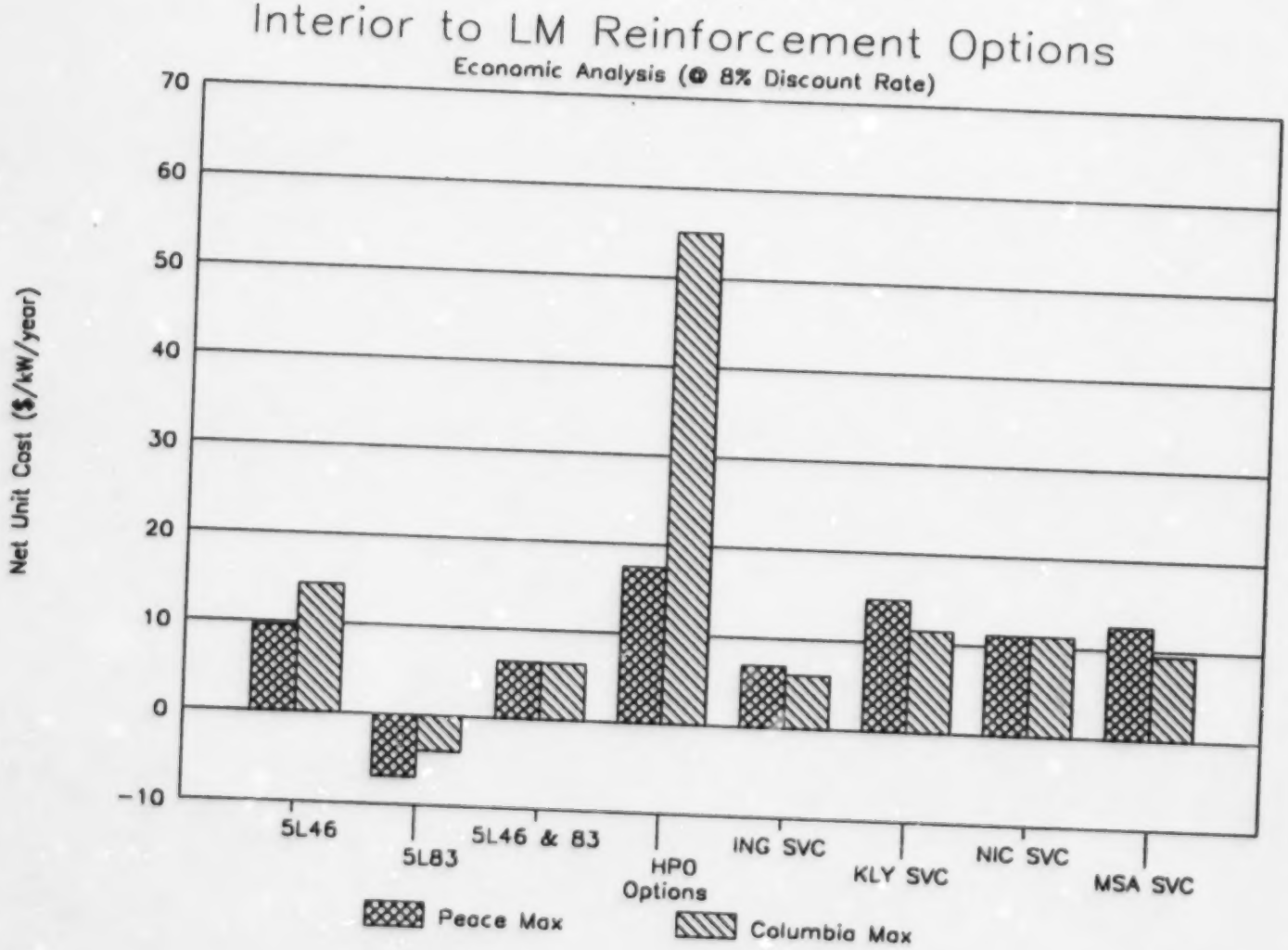

Interior to LM Reinforcement Options
Economic Analysis (@ 8% Discount Rate)
Net Unit Cost ($/kW/year)
70
60
50
40
30
20
10
0
-10
5L46
5L83
5L46 & 83
HPO Options
ING SVC
KLY SVC
NIC SVC
MSA SVC
Peace Max
Columbia Max
04-Mar-91

FIGURE 3(a)

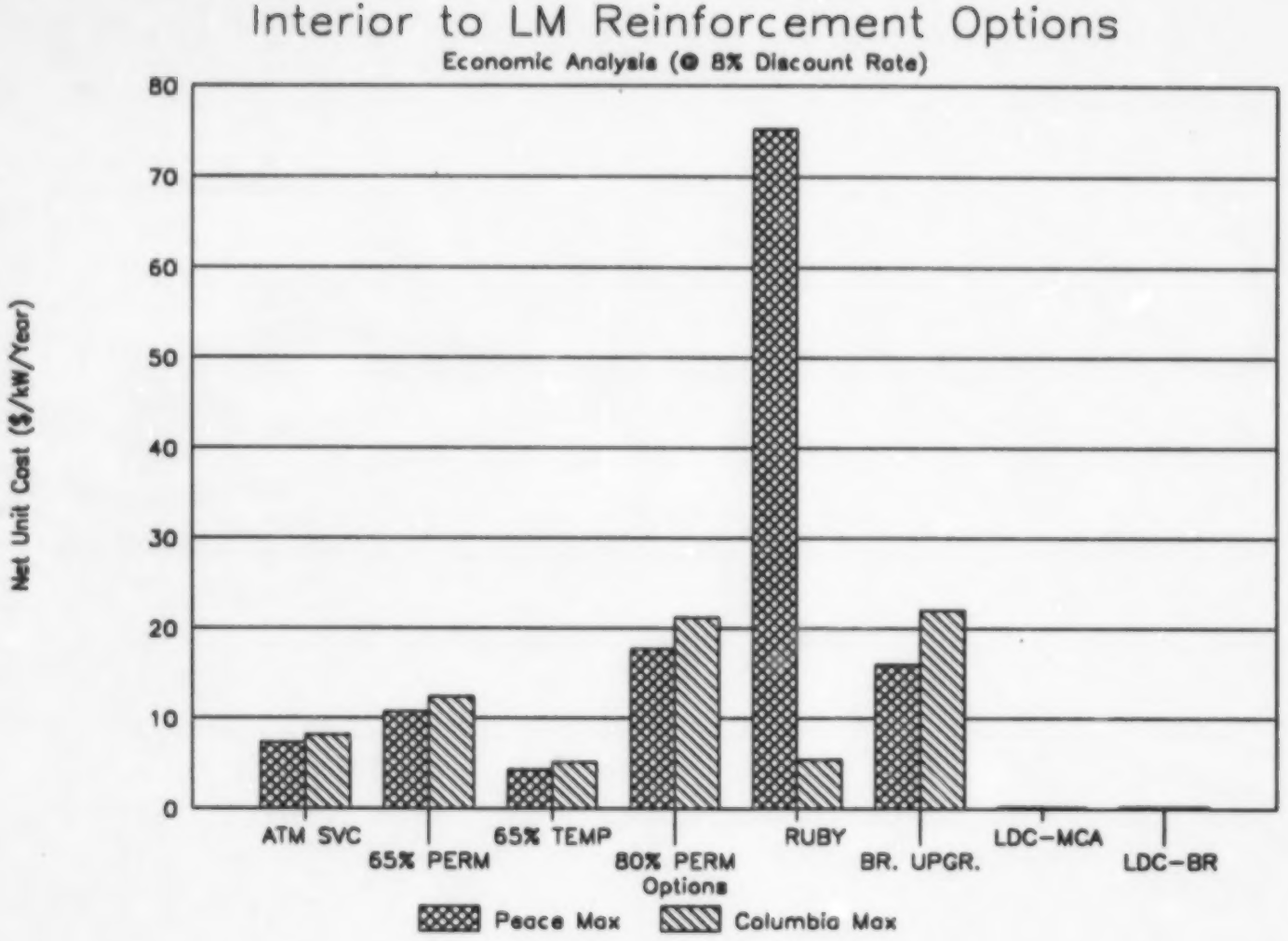

Interior to LM Reinforcement Options
Economic Analysis (@ 8% Discount Rate)
Net Unit Cost ($/kW/Year)
80
70
60
50
40
30
20
10
0
ATM SVC
65% PERM
65% TEMP
80% PERM
RUBY
BR. UPGR.
LDC–MCA
LDC–BR
Options
Peace Max
Columbia Max
27-Mar-91

FIGURE 3(b)

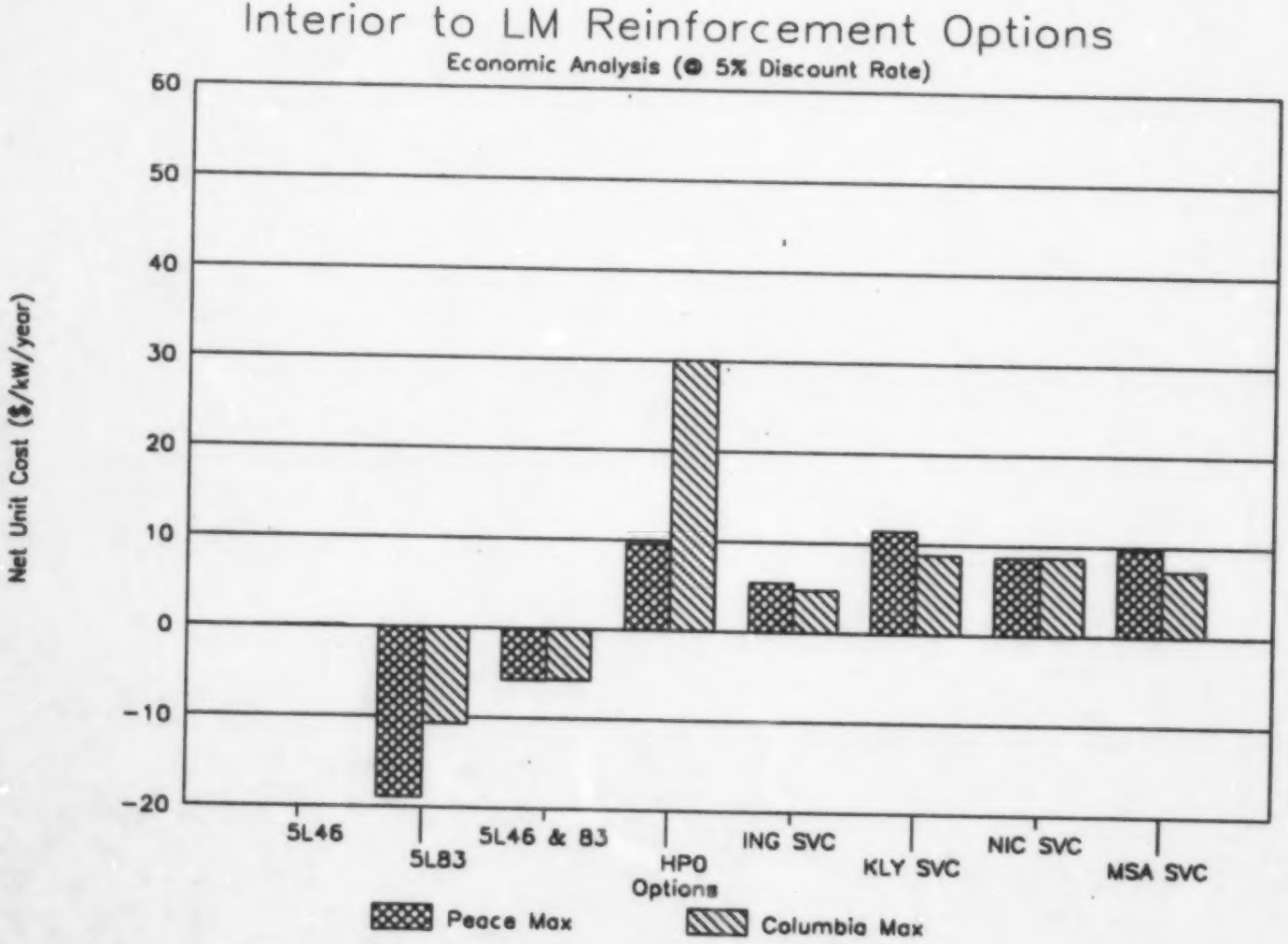

Interior to LM Reinforcement Options
Economic Analysis (@ 5% Discount Rate)
Net Unit Cost ($/kW/year)
60
50
40
30
20
10
0
-10
-20
5L46
5L83
5L46 & 83
HPO Options
ING SVC
KLY SVC
NIC SVC
MSA SVC
Peace Max
Columbia Max
04-Mar-91

FIGURE 4(a)

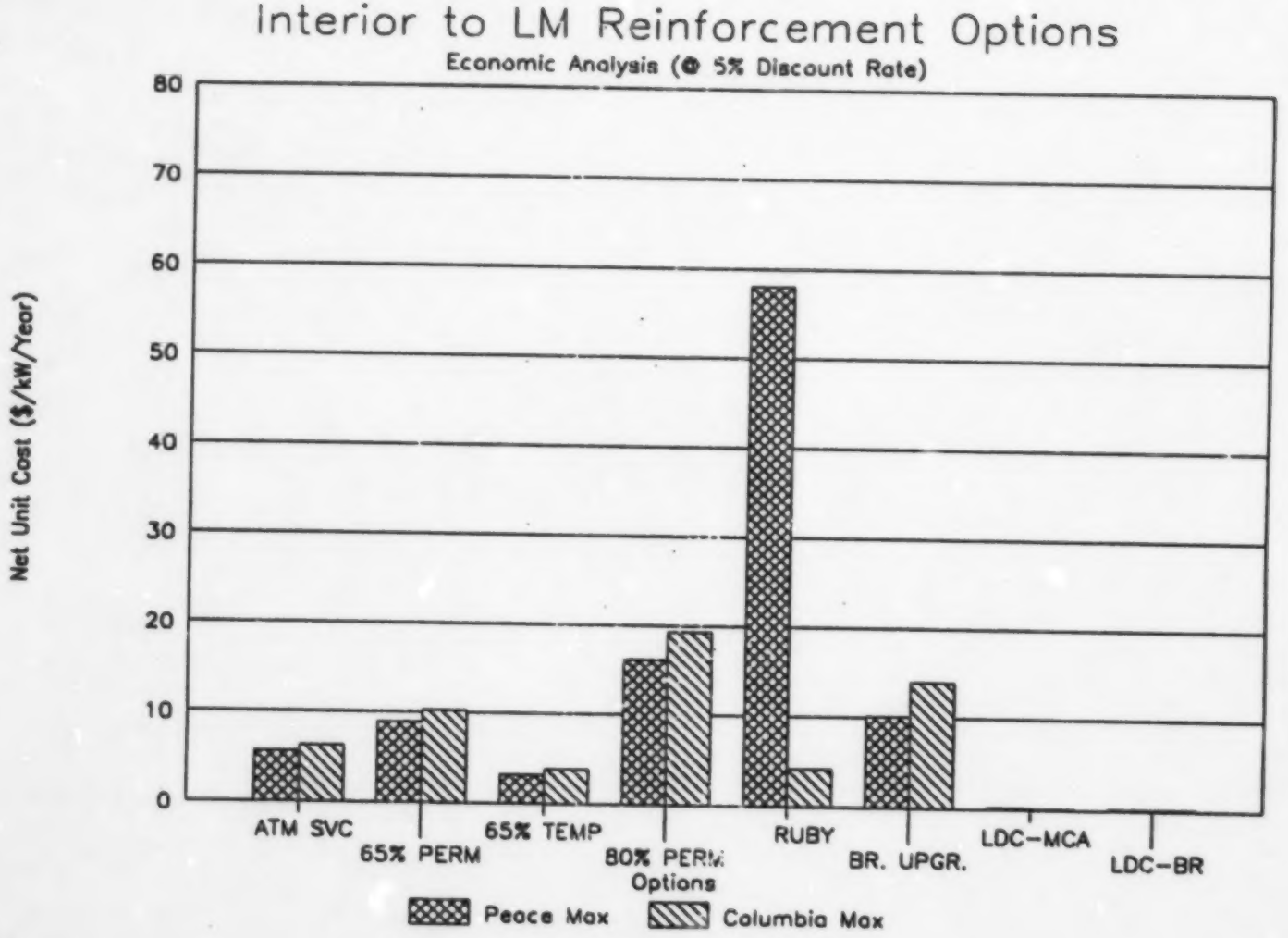


FIGURE 4(b)

27-Mar-91

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN

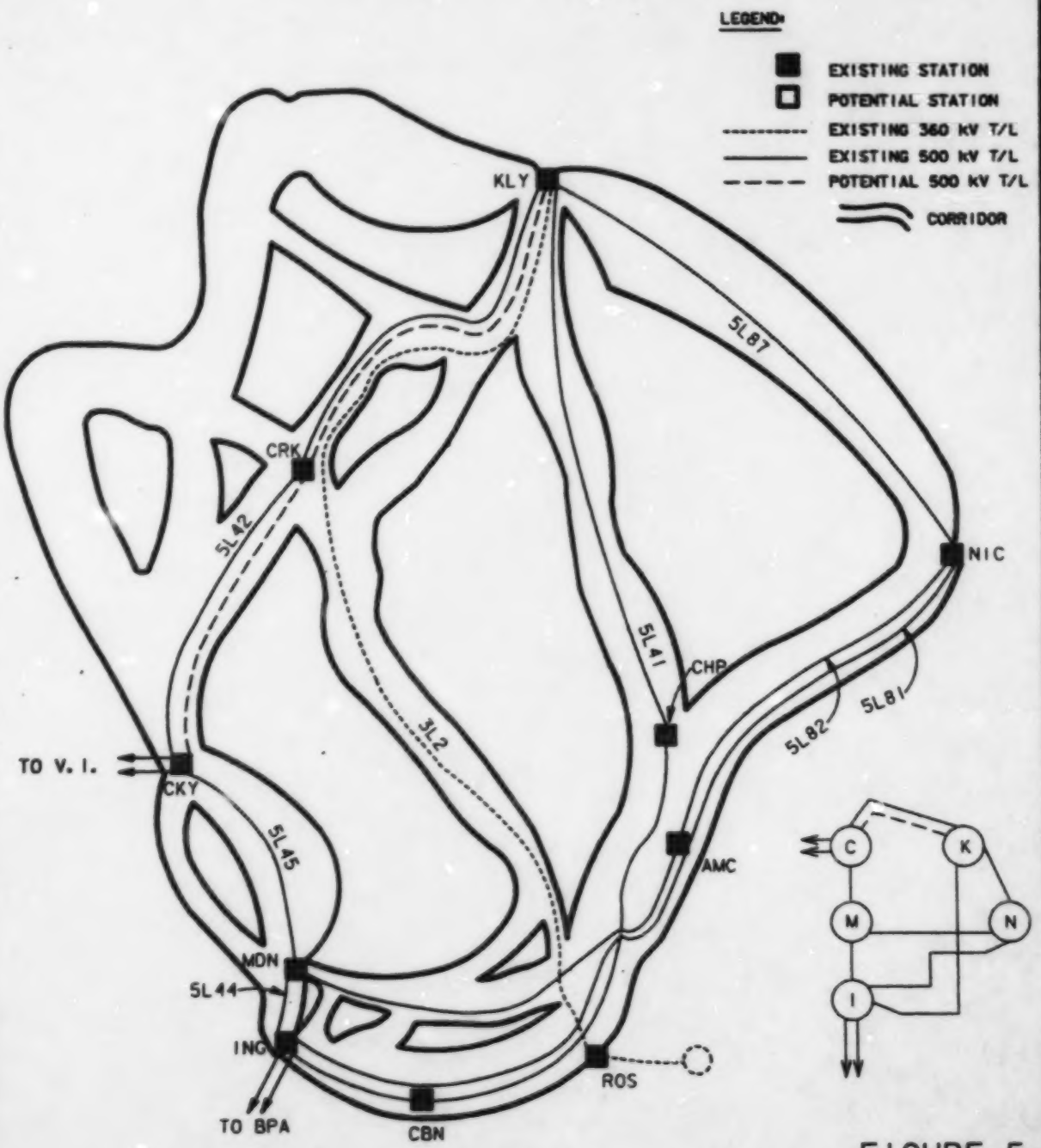


FIGURE 5

KELLY LAKE - CHEEKYE

*2 500 kV TRANSMISSION LINE

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN

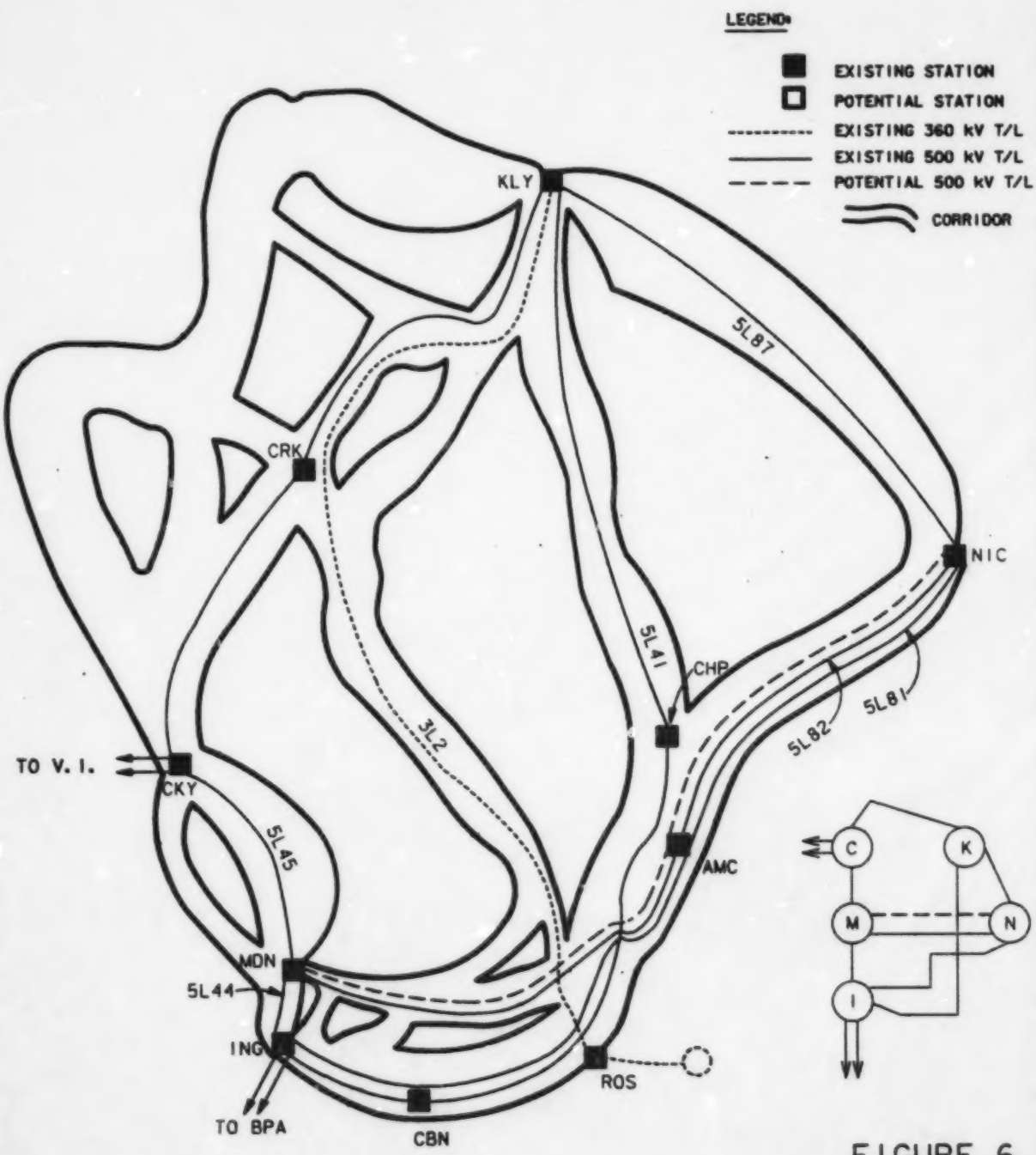
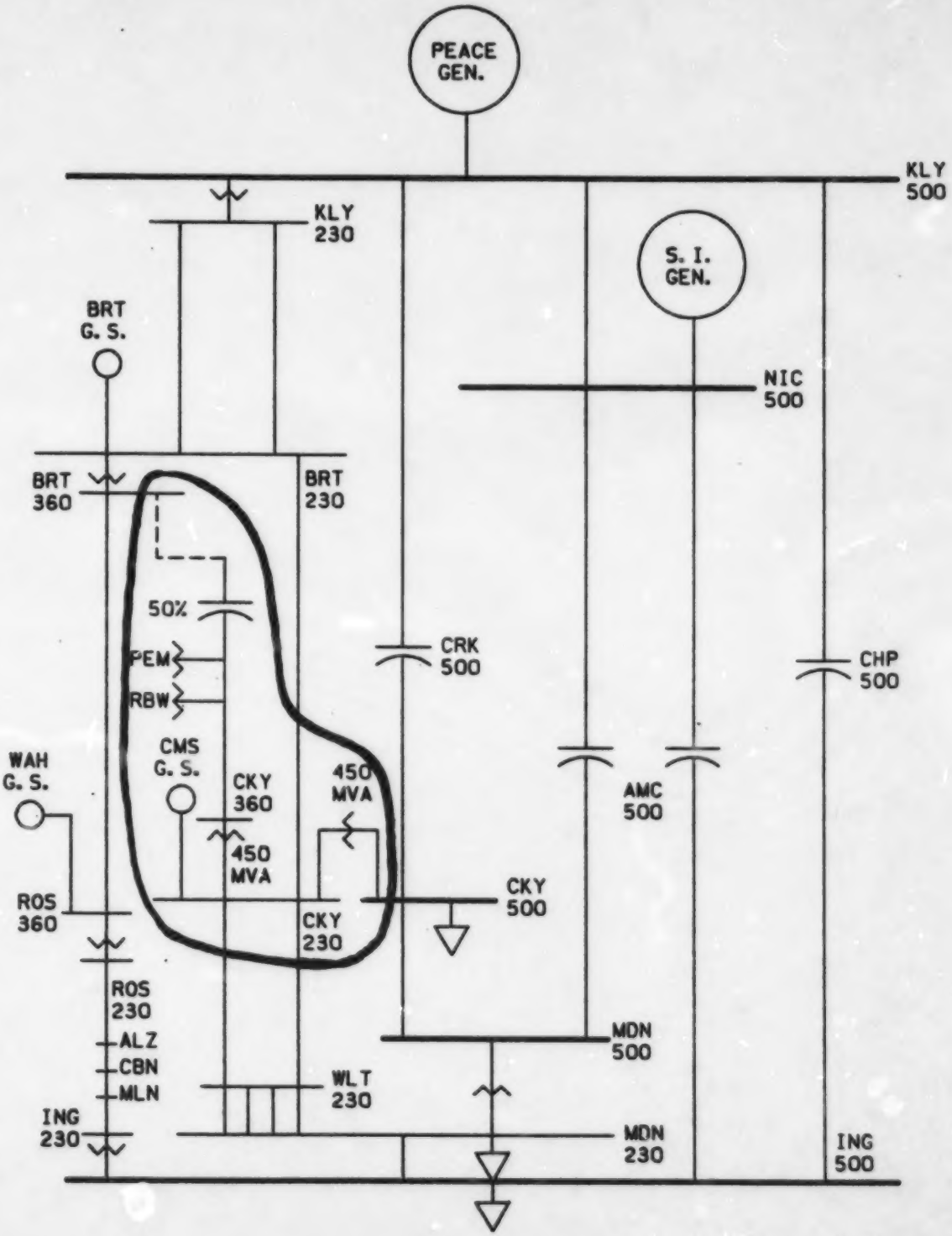


FIGURE 6

NICOLA - MERIDIAN

#2 500 kV TRANSMISSION LINE



C:\DGN\444\C12

B.C. HYDRO INT-LM BULK TRANSMISSION SYSTEM

BRIDGE RIVER SYSTEM REINFORCEMENT

FIGURE 7

15 NOV 90

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN

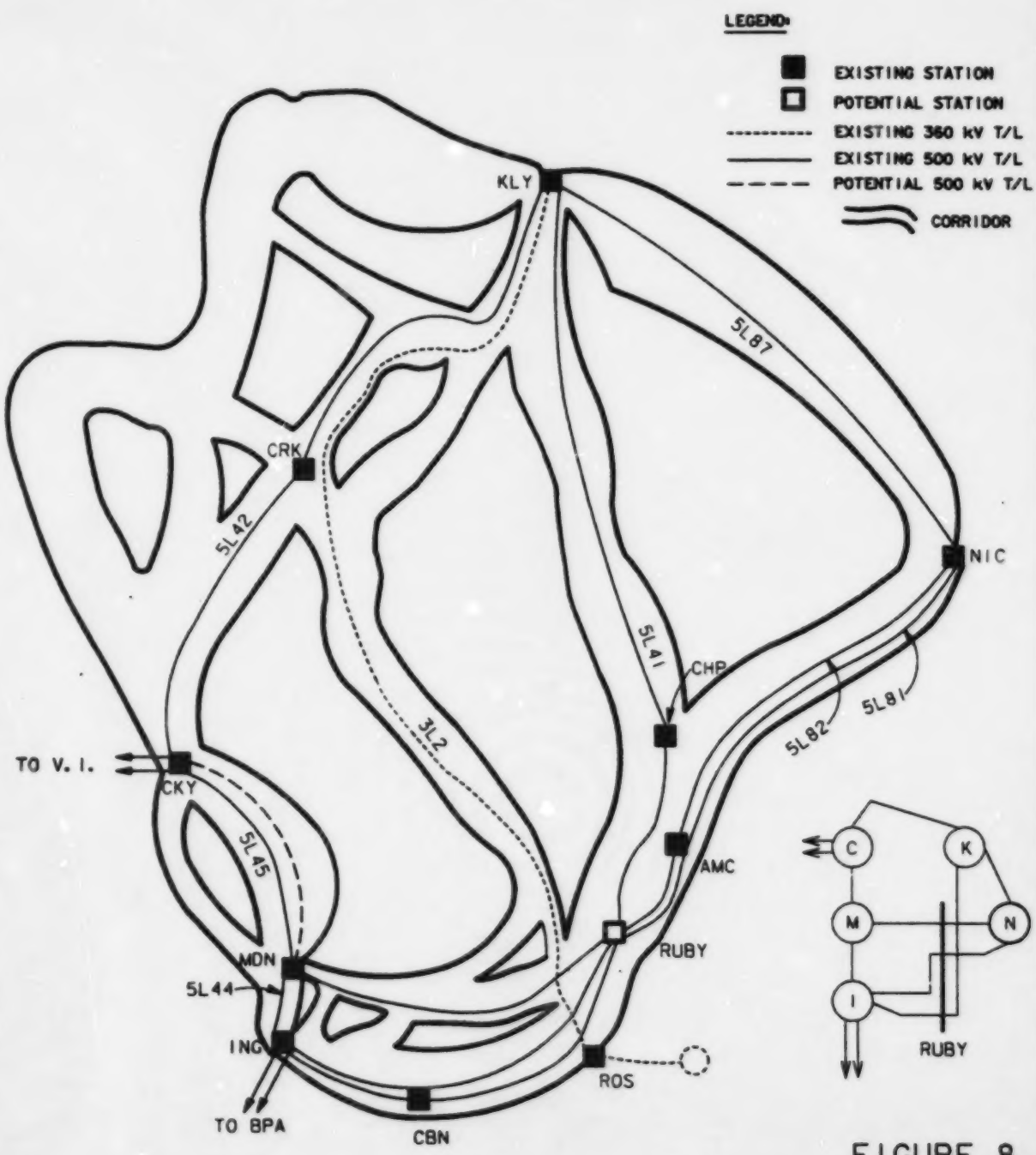


FIGURE 8
500 kV SWITCHING STATION
NEAR RUBY CREEK

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN

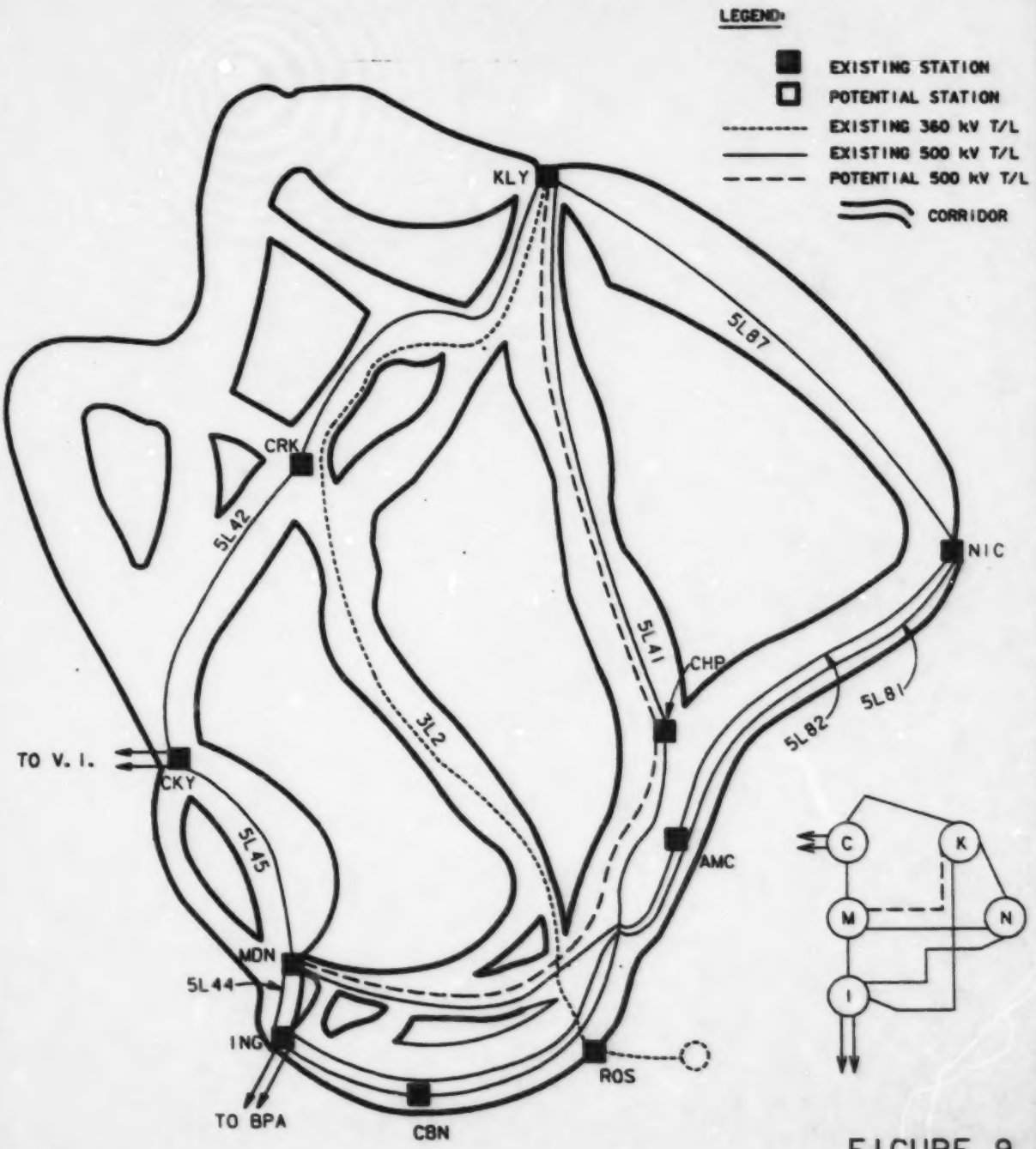


FIGURE 9

KELLY LAKE - MERIDIAN

#2 500 kV TRANSMISSION LINE

DGM 444 CJ4

INTERIOR-LOWER MAINLAND TRANSMISSION PLAN

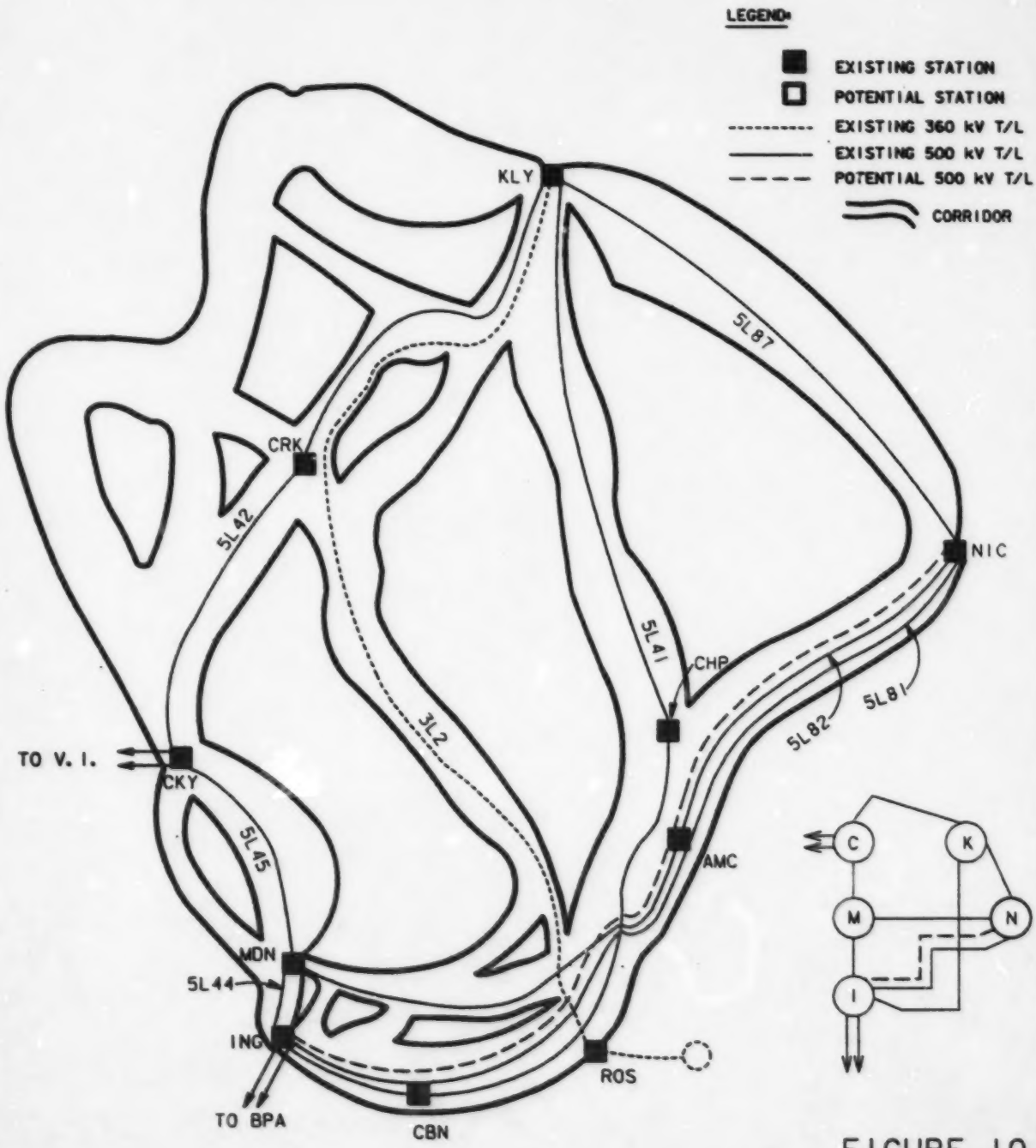


FIGURE 10

NICOLA - INGLEDOW

#2 500 kV TRANSMISSION LINE

DGM 446 CJ4

APPENDIX 2

TABLES

TABLES

1. OPTION SUMMARY

2. INT-LM REINFORCEMENT OPTIONS - VOLTAGE STABILITY ANALYSIS

3. INT-LM REINFORCEMENT OPTIONS - ECONOMIC ANALYSIS (@ 8% DISCOUNT RATE)

4. INT-LM REINFORCEMENT OPTIONS - ECONOMIC ANALYSIS (@ 5% DISCOUNT RATE)

TABLE 1

LEGEND

Cat	Project Category
Project	Major Project Name
Description	Component to be added
Ranking	Qualitative Assessment (Bar Chart)
R	Qualitative Assessment (Numeric)

Factors

TECH	Technical Feasibility
COST	Cost Performance
LT	Lead Time, Years

Action

LF	Flowability Studies
QV	Voltage Stability Studies
EST	Obtain Cost Estimate
CONS	Consultation with other BCH departments
B/F When:	Condition under which the option is to be re-considered

CLS	Option Class

Interior to Lower Mainland 500 kV Transmission Reinforcement

TABLE 1

Option Summary

Ref. No.	Cat	Project	Description	Ranking	R	Factors			Action					Remarks	CLB
						TECH	COST	LT	LF	QV	EST	CONS	B/F When:		
1	A	Kelly Lake -	T/L and series	[redacted]	9	Very Good	Fair	6						Needed for Peace side of	A
		Cheekye 500 kV #2	caps(remove 2L1)											INT-LM t/mission	
2	B	Gen LDC	LDC electronics at	[redacted]	9	Fair	Good	1-2		•	•	CCP		Requires JVC scheme	B
			major plants									PCD			
3	C	Sh/caps for Pre-	At LM/VI load buses	[redacted]	9	Good	Very Good	2		•	•	ATP		Requires site specific	A
		disturb Dynamic Vars										SP		studies	
4	C	Static Var	NIC/KLY/ING/MSA	[redacted]	8	Good	Fair	3		•		SP		Allows T/L staging	A
		Compensation(SVC)	SVC's												
5	A	NIC-MDN #2 500 kV	T/L and series caps	[redacted]	8	Very Good	Fair	9	•	•	•	TED		Needed for Columbia side	A
														of INT-LM t/mission	
6	A	BR.RIV.Upgrade	Circuit 2L2 at 360kV	[redacted]	7	Good	Good	3	•	•	•	SP			B
7	D	BR.RIV.Upgrade	2L2(360 kV) 50%	[redacted]	7	Fair	Fair	3	•	•	•	SP		Re-establish Tladoli	B
8	D	Perm increase Series	CHP/CRK/AMC	[redacted]	7	Good	Good	5	•	•	•	PP		Assumes Protection is OK	A
		Compensation	50-65%									SP			
9	A	NIC-ING#2 500 kV	T/L and series caps	[redacted]	7	Good	Fair	10	•	•	•	TED	If KLY-MDN		C
													instead of 5L46		
10	B	Gen LDC	LDC electronics at	[redacted]	7	Poor	Good	2		•	•	CCP		Gens already hit limits	D
			small LM/VI plants									PCD			
11	E	500 kV Switching	Ruby Creek	[redacted]	6	Fair	Poor	5	•	•	•	SP		Protection issues/effective	A
		Station	5L81/5L82/5L41									PP		only on Columbia side	
12	C	Synch Condenser	BUT #5/6	[redacted]	6	Fair	Good	3		•	•	OP	BUT long-term		C
												SP	role defined		
13	J	Demand Side Mgmt	Power Smart	[redacted]	6	Good	Very Good							Ongoing	A
14	F	VI Area Transmission	Vanc Is. advance	[redacted]	6	Fair	Good	3-4	•	•	•	ATP	Site specific		C
		Upgrade	conversion to 230 kV										studies done		

A EHV Transmission Line
B Generator Voltage/Var Control
C Provision of dynamic Vars
D Series Compensation
E Sectionalizing
F ATM Reinforcement
G Provision of Static Vars
H RAS Scheme
I HVDC/UHV Transmission Line
J Load Displacement

TABLE 1 (cont'd)

Ref. No.	Cat	Project	Description	Ranking	R	Factors			Action					Remarks	CLS
						TECH	COST	LT	LF	QV	EST	CONS	B/F When:		
15	F	LM/FV Area	Advance various	[redacted]	6	Fair	Good	3-4	•	•	•	ATP	Site specific		
		T/mission Upgrade	reinforcements										studies done		C
16	A	KLY-MDN 500kV #1	T/L and series caps	[redacted]	6	Good	Fair	10	•	•	•	TED	Peace R/I after	ROW issues	C
17	H	HVDC Runback	Various electronics	[redacted]	5	Fair	Very Good	2	•	•	•	CCP	5L46		
18	H	Temp Boost in Series	CHP/CRK/AMC to65%	[redacted]	5	Fair	Good	3	•	•	•	PP		Pre-disturb. HVDC level?	D
		Compensation										SP	Reliability		C
19	D	Series Caps on	CUS-MON 500 kV	[redacted]	5	Good	Good	5		•	•	BPA	proven		
		BPA Ties										SP	BCH/BPA joint	BCH/BPA Cost/Operating	C
20	D	New 50% Series	5L87 50% series	[redacted]	6	Fair	Fair	4	•	•	•	SP	planning	Agreements required	
		Compensation	compensation											Tighten KLY-NIC	A
21	G	Mech. Sw. Caps	At load centre buses	[redacted]	4	Poor	Good	2		•	•	SP	Dynamic load	connection	
22	C	Static Var	At substns away	[redacted]	4	Good	Fair	3		•	•	CCP	char known	Would reduce SVC costs	C
		Compensator	from 500 kV									SP	LM SVC		
23	H	AGC Runback	EMS runback scheme	[redacted]	4	Poor	Good	2		•	•		optimized		C
			for Peace/Col gen									CCP			
24	A	KLY-CBL 500 kV #1	T/L and series	[redacted]	4	Fair	Poor	10	•	•	•	TED	Homathko		D
			caps										Integration studied		
25	D	Perm Increase Series	CHP/CRK/AMC	[redacted]	3	Poor	Good	7	•	•	•	PP	Protn issue -		C
		Compensation	66-80%										clarified		
26	C	LM Coordinated	BUT/ING/MDN/etc	[redacted]	3	Fair	Very Good	4		•	•	PCD	Dynamic load	Coordination of LM	C
		Var Control											char known	var sources	

A EHV Transmission Line
B Generator Voltage/Var Control
C Provision of dynamic Vars
D Series Compensation
E Sectionalizing
F ATM Reinforcement
G Provision of Static Vars
H RAS Scheme
I HVDC/UHV Transmission Line
J Load Displacement

TABLE 1 (cont'd)

Ref. No.	Cat	Project	Description	Ranking	R	Factors			Action					Remarks	CLS
						TECH	COST	LT	LF	QV	EST	CONS	B/F When:		
27	H	OLTC Blocking	Block OLTC action		3	Poor	Good	4	*	*	*	CCP		No OLTC on 500/230 kV	D
														tx's/OLTC on distbn txs	
28	I	INT-LM HVDC	NIC/KLY-ING/MDN		3	Fair	Poor	10	*	*	*	TED	Costs lower	Good for power routing	C
29	I	INT-LM 765 kV AC	NIC/KLY-ING/MDN		3	Fair	Poor	10	*	*	*	TED	No new INT-LM	Reliability issue	C
												SP	ROW available		
30	C	EHV Over Voltage	Xfmr taps		3	Poor	Very Good	2	*	*		SP			D
		operation										OP			
31	A	DMR-PIK T/M	Operate at 500 kV		3	Fair	Good	3	*	*	*	SP		Not effective	D
32	C	Mid-Line SVC's	CHP/CRK/AMC		2	Poor	Fair	4		*	*	SP	Protection	May be optimal location for	C
												PP	Issues resolved	SVC but feasibility an issue	
33	H	Auto Phase Shift	WWP/NLY		2	Poor	Very Good	2	*	*	*	SP		Could serve both BCH and	D
		Control	phase shifters											BPA requirements	
34	A	High Phase Order	BRT-ING 360 kV		2	Good	Poor	6	*	*	*	TED			D
		T/mission	BRT-CKY 360 kV									PP			
35	J	LM/VI generation	Burrard generation		1	Good	Fair	4		*	*	POW	Operating issues		C
													resolved		
36	C	Trip Shunt Reactors	Transfer trip to		1	Poor	Very Good	2		*		CCP		Risk of overvoltage	D
			KLY/NIC 500 kV rx.												
37	H	Load Shedding	Load shed on Single		1	Fair	Fair	2		*	*	OPS	Criteria	Volt or transfer trip	C
			Contingencies									SP	changed	initiated?	

A EHV Transmission Lines
B Generator Voltage/Var Control
C Provision of dynamic Vars
D Series Compensation
E Sectionalizing
F ATM Reinforcement
G Provision of Static Vars
H RAS Scheme
I HVDC/UHV Transmission Line
J Load Displacement

Interior to Lower Mainland Transmission Capability
Reinforcement Options - Voltage Stability Analysis

OPTIONS ——>	Base Case	SL46	SL83	SL46 & 83	HP0	ING SVC	KLY SVC	NIC SVC	MSA SVC
Load1	8702	8702	8702	8702	8702	8702	8702	8702	8702
Load2	9202	9202	9702	9202	9202	9202	9202	9202	9202
Loss Load1	722	683	671	641		722	722	722	722
Loss Load2	735	695	683	653		735	735	735	735
OVbus1	1201	1201	1201	1201	1201	1201	1201	1201	1201
Ores P max Load1	1	267	222	480	385	184	111	143	146
Ores C max Load1	24	146	371	425	105	207	145	148	187
Ores P max Load2	-171	92	86	310	405	14	-53	-18	-39
Ores C max Load2	-122	23	249	284	115	62	5	7	34
OVbus2	202	202		202	202	202	202	202	202
Ores P max Load1	17	321		488	245	193	114	154	291
Ores C max Load1	63	215		461	105	248	205	195	326
Ores P max Load2	-142	165		408		70	-41	4	156
Ores C max Load2	-79	83		393		132	58	49	208
OVbus3	2216	2216		2216		2216	2216	2216	2216
Ores P max Load1	46	295		395		207	106	136	321
Ores C max Load1	86	207		375		240	185	184	360
Ores P max Load2	-129	181		327		96	-13	22	144
Ores C max Load2	-57	103		315		143	71	89	244
P. Limit OVbus1	8704	9465	9517	10109	10200	9244	9041	9147	9098
P. Limit OVbus2	8756	9728		11736	9700	9487	9070	9217	9782
P. Limit OVbus3	8832	9992		11606		9634	9148	9300	9610
C. Limit OVbus1	8784	9296	10222	10206	9100	9413	9219	9226	9314
C. Limit OVbus2	8923	9516		12079	9100	9768	9399	9369	10082
C. Limit OVbus3	9001	9700		11801		9936	9512	9505	10258
System Limits:									
OVbus1	8704	9296	9517	10109	9100	9244	9041	9147	9098
OVbus2	8756	9516		11736	9100	9487	9070	9217	9782
OVbus3	8832	9700		11606		9634	9148	9300	9610
Overall Limits:									
Peace Max:	8704	9465	9517	10109	9700	9244	9041	9147	9098
Columbia Max:	8784	9296	10222	10206	9100	9413	9219	9226	9314
Limit Increase:									
Peace Max:	0	761	813	1405	996	540	336	442	394
Columbia Max:	0	512	1438	1422	316	629	435	442	530
INT-LM Cap'y Incr Due to Prj Add'n:									
Peace Max:	0	533	569	983	697	378	235	310	275
Columbia Max:	0	359	1007	995	221	440	304	309	371

Notes:

1. Losses are based on a 1994/95 system configuration.
2. Interior to Lower Mainland Flow is assumed to be approx. 70% of BCH load.
3. The results for the Option 'HP0' are provided by Power Tech. Labs. It is assumed that 50 Mvar increase in Q reserve equates to approx. 200 MW (equiv. to one year load growth) increase in system capability.
4. Capacity increase figures updated to 2% Droop criteria (WSC's 1989 studies).

TABLE 2(a)

Interior to Lower Mainland Transmission Capability
Reinforcement Options - Voltage Stability Analysis

OPTIONS ——>	Base Case	ATM SVC	65% PER	65% TEMP	80% PER	RUBY	BR. UPGR	LDC-MCA	LDC-BR
Load1	8702	8702	8702	8702	8702	8702	8702	8702	8702
Load2	9202	9202	9202	9202	9202	9202	9202	9202	9202
Loss Load1	722		729		752	724	720	719	722
Loss Load2	735		741		765	737	733	734	735
QVbus1	1201					1201	1201	1201	1201
Qres P max Load1	1					33	59	41	61
Qres C max Load1	24					350	56	65	74
Qres P max Load2	-171					-137	-100	-120	-103
Qres C max Load2	-122					226	-74	-72	-65
QVbus2	202					202	202	202	202
Qres P max Load1	17					49	88	57	73
Qres C max Load1	63					382	109	107	114
Qres P max Load2	-142					-104	-75	-92	-80
Qres C max Load2	-79					275	-40	-36	-27
QVbus3	2216					2216	2216	2216	2216
Qres P max Load1	46					75	111	84	92
Qres C max Load1	86					323	123	101	108
Qres P max Load2	-129					-95	-55	-79	-61
Qres C max Load2	-57					257	-22	-20	-4
P. Limit QVbus1	8704					8800	8887	8830	8889
P. Limit QVbus2	8756					8863	8973	8893	8940
P. Limit QVbus3	8832					8923	9036	8951	9003
C. Limit QVbus1	8784					10112	8917	8939	8968
C. Limit QVbus2	8923					10489	9068	9076	9107
C. Limit QVbus3	9001					11148	9127	9119	9184
System Limits:									
QVbus1	8704					8800	8887	8830	8889
QVbus2	8756					8863	8973	8893	8940
QVbus3	8832					8923	9036	8961	9003
Overall Limits:									
Peace Max:	8704					8800	8887	8830	8889
Columbia Max:	8784					10112	8917	8939	8968
Limit Increase:									
Peace Max:	0					96	183	125	184
Columbia Max:	0					1329	133	155	184
INT-LM Cap'y Incr Due to Prj Add'n:									
Peace Max:	0	600	460	760	860	67	128	88	129
Columbia Max:	0	540	400	640	720	930	93	108	129

Notes:

1. Losses are based on 1994/95 system configuration.
2. Interior to Lower Mainland power flow is assumed to be approx. 70% of BCH load.
3. The QV results of options 'ATM SVC, 65% TEMP/PERM and 80% PERM COMP increased in compensation', are provided by Power Tech Labs. (Reference: Power Tech Project# 2251-20, Stage 3 Report dated November 20, 1990.)
4. Capacity increase figures updated to 2% Droop Criteria (WSC's 1989 studies).

TABLE 2(b)

05-Mar-91

Interior to Lower Mainland Transmission Capability

Reinforcement Options - Economic Analysis (@ 8% D/T)

OPTIONS ——→	SL46	SL83	SL46 & 83	HP0	BKG SVC	KLY SVC	NIC SVC	MBA SVC
Date of Study:	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90
T/L Length (km):	194	248	442	194	0	0	0	0
Value of Cap'y($/kW/yr):	$58	$58	$58	$58	$58	$58	$58	$58
Annual Discount Rate:	8%	8%	8%	8%	8%	8%	8%	8%
T/L Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Stn. Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Int Dur.Const(T/L):	14%	14%	14%	14%	14%	14%	14%	14%
Int Dur.Const(Stn):	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%
T/L Taxes ($/km):	4208	4208	4208	4208	4208	4208	4208	4208
Stn Tax Rate:	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
T/L Annual Maintenance:	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Stn Annual Maintenance:	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
T/L Economic Life (yrs):	45	45	45	45	45	45	45	45
Stn Economic Life (yrs):	30	30	30	30	30	30	30	30
Loss Factor:	60%	60%	60%	60%	82%	82%	82%	82%
Value of Engy.($/MW.h):	$53	$53	$53	$53	$53	$53	$53	$53
Sys Peak Losses (MW):	-35	-78	-98	-19	1	1	1	1
T/L Direct Costs ($000):	125021	173698	298919	120000	0	0	0	0
Stn Direct Costs ($000):								
Series Capacitor:	8643	10400	19043	0	0	0	0	0
Terminations	13704	13310	27014	0	0	0	0	0
Others	1646	0	1646	44000	19000	26400	26400	26400
Total Stn Dir Costs:	23993	23710	47703	44000	19000	26400	26400	26400
Loaded T/L Costs ($000):	152526	212156	364681	146400	0	0	0	0
Loaded Stn Costs ($000):	27736	27409	55145	50864	21964	30518	30518	30518
Cap. Cost as % Of Dir.Cost:	121.0%	121.2%	121.1%	120.3%	115.6%	115.6%	115.6%	115.6%
Equiv. Annualized Costs:								
T/L Capital ($000/a):	12597	17521	30118	12091	0	0	0	0
Stn Capital ($000/a):	2464	2435	4898	4518	1951	2711	2711	2711
T/L Maintenance ($000/a):	750	1043	1794	720	0	0	0	0
Stn Maintenance ($000/a):	288	285	572	528	228	317	317	317
T/L Taxes ($000/a):	816	1045	1860	816	0	0	0	0
Stn Taxes ($000/a):	0	0	0	0	0	0	0	0
Proj Ann. Costs ($000/a):	16915	22329	39242	18673	2179	3028	3028	3028
System Losses ($000/a):	-11780	-26252	-32984	-6496	439	439	439	439
Net Ann. Cost ($000/a):	5135	-3924	6259	12177	2618	3466	3466	3466
Annual Cost Factor :	11.4%	11.3%	11.3%	11.4%	11.5%	11.5%	11.5%	11.5%
INT-LM Cap'y Incr Due to Prj Add'n:								
a. Max. Peace Gen.:	533	569	983	897	378	235	310	275
b. Max. Columbia Gen:	359	1007	995	221	440	304	309	371
Net Unit Cost ($/kW/a) For:								
a. Max. Peace Gen.:	$9.64	-6.89	$6.36	$17.47	$6.93	$14.72	$11.20	$12.58
b. Max. Columbia Gen:	$14.32	-3.90	$6.29	$55.03	$5.95	$11.39	$11.21	$9.35

Notes:

1. Costs are based on 1990 budget estimates.
2. Value of Capacity and Energy are the cost of new electricity supply delivered to the Lower Mainland in year 2002/03 in October 1990 dollars.
3. Losses for SL46, SL83, SL46 & SL83 were derived in Sequence Study Report SP9011.
4. Annual Cost Factor is a ratio of the Project Annual Cost to the Direct Transmission and Substation Cost.
5. The Net Unit Cost is determined by dividing the Net Annual Cost by the Increase in Interior to Lower Mainland Transfer Capability.

TABLE 3(a)

Interior to Lower Mainland Transmission Capability
Reinforcement Options - Economic Analysis (@ 8% DR)

OPTIONS ——→	ATM SVC	60% PER	60% TEMP	60% PER	RUBY	BR. UPGR	LDC-MCA	LDC-BR
Date of Study:	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90
T/L Length (km):	0	0	0	0	0	0	0	0
Value of Cap'y ($/kW/yr):	$58	$58	$58	$58	$58	$58	$58	$58
Annual Disc. Rate:	8%	8%	8%	8%	8%	8%	8%	8%
T/L Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Stn. Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Int Dur.Const(T/L):	14%	14%	14%	14%	14%	14%	14%	14%
Int Dur.Const(Stn):	7.6%	7.6%	7.6%	7.6%	7.6%	7.6%	4.3%	4.3%
T/L Taxes ($/km):	4208	4208	4208	4208	4208	4208	4208	4208
Stn Tax Rate:	0%	0%	0%	0%	0%	0%	0%	0%
T/L Annual Maintenance:	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Stn Annual Maintenance:	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
T/L Economic Life (yrs):	45	45	45	45	45	45	45	45
Stn Economic Life (yrs):	30	30	30	30	30	30	30	30
Loss Factor:	82%	82%	82%	82%	60%	60%	98%	98%
Value of Engy.($/MW.h):	$53	$53	$53	$53	$53	$53	$53	$53
Sys Peak Losses (MW):	1	4	0	23	2	-3	0	0
T/L Direct Costs ($000):								
Stn Direct Costs ($000):								
Series Capacitor:	0	0	0	0	0	0	0	0
Terminations	0	0	0	0	0	0	0	0
Others	34400	27720	28720	44760	39000	25225	173	273
Total Stn Dir Costs:	34400	27720	28720	44760	39000	25225	173	273
Loaded T/L Costs ($000):	0	0	0	0	0	0	0	0
Loaded Stn Costs ($000):	39766	32044	33200	51743	45084	29160	194	307
% of Direct Cost:	115.6%	115.6%	115.6%	115.6%	115.6%	115.6%	112.3%	112.3%
Equiv. Annualized Costs:								
T/L Capital ($000/a):	0	0	0	0	0	0	0	0
Stn Capital ($000/a):	3532	2846	2949	4596	4005	2590	17	27
T/L Maintenance($000/a):	0	0	0	0	0	0	0	0
Stn Maintenance ($000/a):	413	333	345	537	468	303	2	3
T/L Taxes ($000/a):	0	0	0	0	0	0	0	0
Stn Taxes ($000/a):	0	0	0	0	0	0	0	0
Proj Ann. Costs ($000/a):	3945	3179	3294	5133	4473	2893	19	31
System Losses ($000/a):	439	1755	0	10090	570	-845	0	0
Net Ann. Cost ($000/a):	4384	4934	3294	15224	5043	2048	19	31
Annual Cost Factor	11.5%	11.5%	11.5%	11.5%	11.5%	11.5%	11.2%	11.2%
INT-LM Cap'y Incr Due to Prj Add'n:								
a. Max Peace Gen.:	800	460	760	960	57	128	88	129
b. Max. Columbia Gen.:	540	400	640	720	930	93	108	129
Net Unit Cost ($/kW/a) For:								
a. Max. Peace Gen.:	$7.31	$10.73	$4.33	$17.70	$75.28	$15.99	$0.22	$0.24
b. Max. Columbia Gen.:	$8.12	$12.33	$5.15	$21.14	$5.42	$21.99	$0.18	$0.24

Notes:

1. Costs are based on 1990 budget estimates.
2. Value of Capacity and Energy are the cost of new electricity supply delivered to the Lower Mainland in year 2002/03 in October 1990 dollars.
3. Annual Cost Factor is a ratio of the Project Annual Cost to the Direct Transmission and Substation Cost.
4. The Net Unit Cost is determined by dividing the Net Annual Cost by the increase in Interior to Lower Mainland Transfer Capability.

TABLE 3(b)

Interior to Lower Mainland Transmission Capability
Reinforcement Options - Economic Analysis (@ 8% DR)

OPTIONS ——>	SL46	SL83	SL46 & SS	HP8	SN3 SVC	KLY SVC	NIC SVC	MSA SVC
Date of Study:	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90
T/L Length (km):	194	248	442	194	0	0	0	0
Value of Cap'y($/kW/yr):	$58	$58	$58	$58	$58	$58	$58	$58
Annual Discount Rate:	5%	5%	5%	5%	5%	5%	5%	5%
T/L Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Stn. Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Int Dur.Const(T/L):	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
Int Dur.Const(Stn):	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%
T/L Taxes ($/km):	4208	4208	4208	4208	4208	4208	4208	4208
Stn Tax Rate:	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
T/L Annual Maintenance:	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Stn Annual Maintenance:	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
T/L Economic Life (yrs):	45	45	45	45	45	45	45	45
Stn Economic Life (yrs):	30	30	30	30	30	30	30	30
Loss Factor:	60%	60%	60%	60%	82%	82%	82%	82%
Value of Engy.($/MW.h):	$53	$53	$53	$53	$53	$53	$53	$53
Sys Peak Losses (MW):	-35	-78	-98	-19	1	1	1	1
T/L Direct Costs ($000):	125021	173898	298919	120000	0	0	0	0
Stn Direct Costs ($000):								
Series Capacitor:	8643	10400	19043	0	0	0	0	0
Terminations	13704	13310	27014	0	0	0	0	0
Others	1646	0	1646	44000	19000	26400	26400	26400
Total Stn Dir Costs:	23993	23710	47703	44000	19000	26400	26400	26400
Loaded T/L Costs ($000):	145774	202765	348540	139920	0	0	0	0
Loaded Stn Costs ($000):	26944	26626	53570	49412	21337	29647	29647	29647
Cap. Cost as % Of Dir.Cost:	115.9%	116.1%	116.0%	115.4%	112.3%	112.3%	112.3%	112.3%
Equiv. Annualized Costs:								
T/L Capital ($000/a):	8202	11408	19609	7872	0	0	0	0
Stn Capital ($000/a):	1753	1732	3485	3214	1388	1929	1929	1929
T/L Maintenance ($000/a):	750	1043	1794	720	0	0	0	0
Stn Maintenance ($000/a):	288	285	572	528	228	317	317	317
T/L Taxes ($000/a):	816	1045	1860	816	0	0	0	0
Stn Taxes ($000/a):	0	0	0	0	0	0	0	0
Proj Ann. Costs ($000/a):	11809	15513	27320	13151	1616	2245	2245	2245
System Losses ($000/a):	-11780	-26252	-32984	-6496	439	439	439	439
Net Ann. Cost ($000/a):	29	-10740	-5664	6655	2055	2684	2684	2684
Annual Cost Factor :	7.9%	7.9%	7.9%	8.0%	8.5%	8.5%	8.5%	8.5%
INT-LM Cap'y Incr Due to Prj Add'n:								
a. Max. Peace Gen.:	533	589	983	897	378	235	310	275
b. Max. Columbia Gen:	359	1007	995	221	440	304	309	371
Net Unit Cost ($/kW/a) For:								
a. Max. Peace Gen.:	$0.05	-18.87	($5.76)	$9.55	$5.44	$11.40	$8.67	$9.74
b. Max. Columbia Gen:	$0.08	-10.67	($5.69)	$30.08	$4.67	$8.82	$8.68	$7.24

Notes:

1. Costs are based on 1990 budget estimates.
2. Value of Capacity and Energy are the cost of new electricity supply delivered to the Lower Mainland in year 2002/03 in October 1990 dollars.
3. Losses for SL46, SL83, SL46 & SL83 were derived in Sequence Study Report SP9011.
4. Annual Cost Factor is a ratio of the Project Annual Cost to the Direct Transmission and Substation Cost.
5. The Net Unit Cost is determined by dividing the Net Annual Cost by the Increase in Interior to Lower Mainland Transfer Capability.

TABLE 4(a)

Interior to Lower Mainland Transmission Capability
Reinforcement Options - Economic Analysis (@ 8% DR)

OPTIONS ——→	ATM SVC	66% PER	66% TEMP	60% PER	RUBY	BR. UPGR	LDC-MCA	LDC-BR
Date of Study:	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90	Nov 90
T/L Length (km):	0	0	0	0	0	0	0	0
Value of Cap'y ($/kW/yr):	$58	$58	$58	$58	$58	$58	$58	$58
Annual Disc. Rate:	8%	8%	8%	8%	8%	8%	8%	8%
T/L Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Stn. Corporate O/H:	8%	8%	8%	8%	8%	8%	8%	8%
Int Dur.Const(T/L):	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%	8.6%
Int Dur.Const(Stn):	4.3%	4.3%	4.3%	4.3%	4.3%	4.3%	2.2%	2.2%
T/L Taxes ($/km):	4208	4208	4208	4208	4208	4208	4208	4208
Stn Tax Rate:	0%	0%	0%	0%	0%	0%	0%	0%
T/L Annual Maintenance:	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%	0.6%
Stn Annual Maintenance:	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
T/L Economic Life (yrs):	45	45	45	45	45	45	45	45
Stn Economic Life (yrs):	30	30	30	30	30	30	30	30
Loss Factor:	82%	82%	82%	82%	60%	60%	98%	98%
Value of Engy.($/MW.h):	$53	$53	$53	$53	$53	$53	$53	$53
Sys Peak Losses (MW):	1	4	0	23	2	-3	0	0
T/L Direct Costs ($000):								
Stn Direct Costs ($000):								
Series Capacitor:	0	0	0	0	0	0	0	0
Terminations	0	0	0	0	0	0	0	0
Others	34400	27720	28720	44760	39000	25225	173	273
Total Stn Dir Costs:	34400	27720	28720	44760	39000	25225	173	273
Loaded T/L Costs ($000):	0	0	0	0	0	0	0	0
Loaded Stn Costs ($000):	38831	31130	32253	50265	43797	28328	191	301
% of Direct Cost:	112.3%	112.3%	112.3%	112.3%	112.3%	112.3%	110.2%	110.2%
Equiv. Annualized Costs:								
T/L Capital ($000/a):	0	0	0	0	0	0	0	0
Stn Capital ($000/a):	2513	2025	2098	3270	2849	1843	12	20
T/L Maintenance ($000/a):	0	0	0	0	0	0	0	0
Stn Maintenance ($000/a):	413	333	345	537	468	303	2	3
T/L Taxes ($000/a):	0	0	0	0	0	0	0	0
Stn Taxes ($000/a):	0	0	0	0	0	0	0	0
Proj Ann. Costs ($000/a):	2926	2358	2443	3807	3317	2145	14	23
System Losses ($000/a):	439	1755	0	10090	570	-845	0	0
Net Ann. Cost ($000/a):	3365	4113	2443	13897	3887	1300	14	23
Annual Cost Factor	8.5%	8.5%	8.5%	8.5%	8.5%	8.5%	8.4%	8.4%
INT-LM Cap'y Incr Due to Prj Add'n:								
a. Max Peace Gen.:	600	460	780	960	67	128	88	129
b. Max. Columbia Gen.:	540	400	640	720	930	93	108	129
Net Unit Cost ($/kW/a) For:								
a. Max. Peace Gen.:	$5.61	$8.84	$3.21	$16.16	$58.03	$10.16	$0.17	$0.18
b. Max. Columbia Gen.:	$6.23	$10.28	$3.82	$19.30	$4.18	$13.97	$0.13	$0.18

Notes:

1. Costs are based on 1990 budget estimates.
2. Value of Capacity and Energy are the cost of new electricity supply delivered to the Lower Mainland in year 2002/03 in October 1990 dollars.
3. Annual Cost Factor is a ratio of the Project Annual Cost to the Direct Transmission and Substation Cost.
4. The Net Unit Cost is determined by dividing the Net Annual Cost by the Increase in Interior to Lower Mainland Transfer Capability.

TABLE 4(b)

APPENDIX 3

SECOND-CONTINGENCY COMPARISONS

APPENDIX 3

Second-contingency Comparisons

1. Introduction

This section describes the results of studies that were done to determine the second-contingency Int-LM transfer capability and peak load line currents for the 5L46 (Option 1), the +200/-100 Mvar Ingledow SVC (Option 4), and the increased the Int-LM series compensation to 65% (Option 8) reinforcement options. The studies added each option to powerflow basecase P8700, i.e the existing 4-line Int-LM system at 1994/95 peak load.

The following second-contingency transmission outages were studied:

5L42/5L45	VI served by local generation and fed radially from Ingledow. VI 500 kV Supply is open at Cheekye;
5L42/5L82	Meridian and Vancouver Island (VI) 500 kV Supply fed radially from Ingledow;
5L41/5L81	Circuits which share a common ROW through parts of Fraser Canyon/Valley and are vulnerable to commmon cause forced outages;
5L44/5L82	Meridian and VI 500 kV Supply fed radially from 5L42.

The procedure was to: 1) add the option to the basecase, 2) define the first-contingency line outage, 3) re-adjust the power flow case to standard conditions, 4) define the second-contingency line outage, and finally 5) develop the QV curve and solve the case for line loadings. The study results apply only until 5L83 is added to the grid.

2. Voltage Stability

Second-contingency Int-LM transfer capabilities are shown in Figure 1. This bar chart figure is aggregated first by reinforcement and then by double outage. The naming convention specifies scheduled outage first and forced outage second.

<u>Observations</u>:

1. Circuit 5L46 provides equal or greater second-contingency Int-LM transfer capability than does either of the two non-transmission options.

2. For a 5L42/5L45 outage, the Int-LM transfer capability for the two non-transmission options was calculated as that provided by 5L46 less the Vancouver Island/Sechelt Peninsula load dropped on opening of the VI 500 kV Supply, i.e.:

   - Circuit 5L46: 5L42/45 K.O. Int-LM transfer capability 7361 MW

- Non-transmission reinforcements:

5L42/45 K.O. load drop on Vancouver Island	765 MW
5L42/45 K.O. load drop on Sechelt Peninsula	100 MW
5L42/45 total load reduction	865 MW
Second-contingency Int-LM capability	6496 MW

3. For a 5L42/5L82 outage, adding 5L46 increases the Int-LM transfer capability 600-700 MW more than does adding either of the non-transmission options.

3. Line Loading

Second-contingency 1994/95 peak load outage currents, without RAS, are shown in Figure 2. The bar chart organization and naming convention are the same as for Figure 1.

Observations:

1. Use of either of the non-transmission options results in second-contingency overloading of 5L81 and 5L82[14] and 1L17 and 1L18[15]. Use of 5L46 does not result in any second-contingency overloads.

2. For either non-transmission option, the limiting 5L42/5L45 second-contingency overload is:

1995/96 VI + Sechelt Peninsula peak load	2320 MW
Less: VI dependable generation and HVDC cable capacity	-1199 MW
Equals: 1L17 + 1L18 (no RAS) loading	1121 MW

This is more than four times the 138 kV AC cable rating; however, it would be relieved by automatically dropping load on Vancouver Island within a few seconds after the outage. The 5L46 option avoids this extreme overload and its associated load dropping.

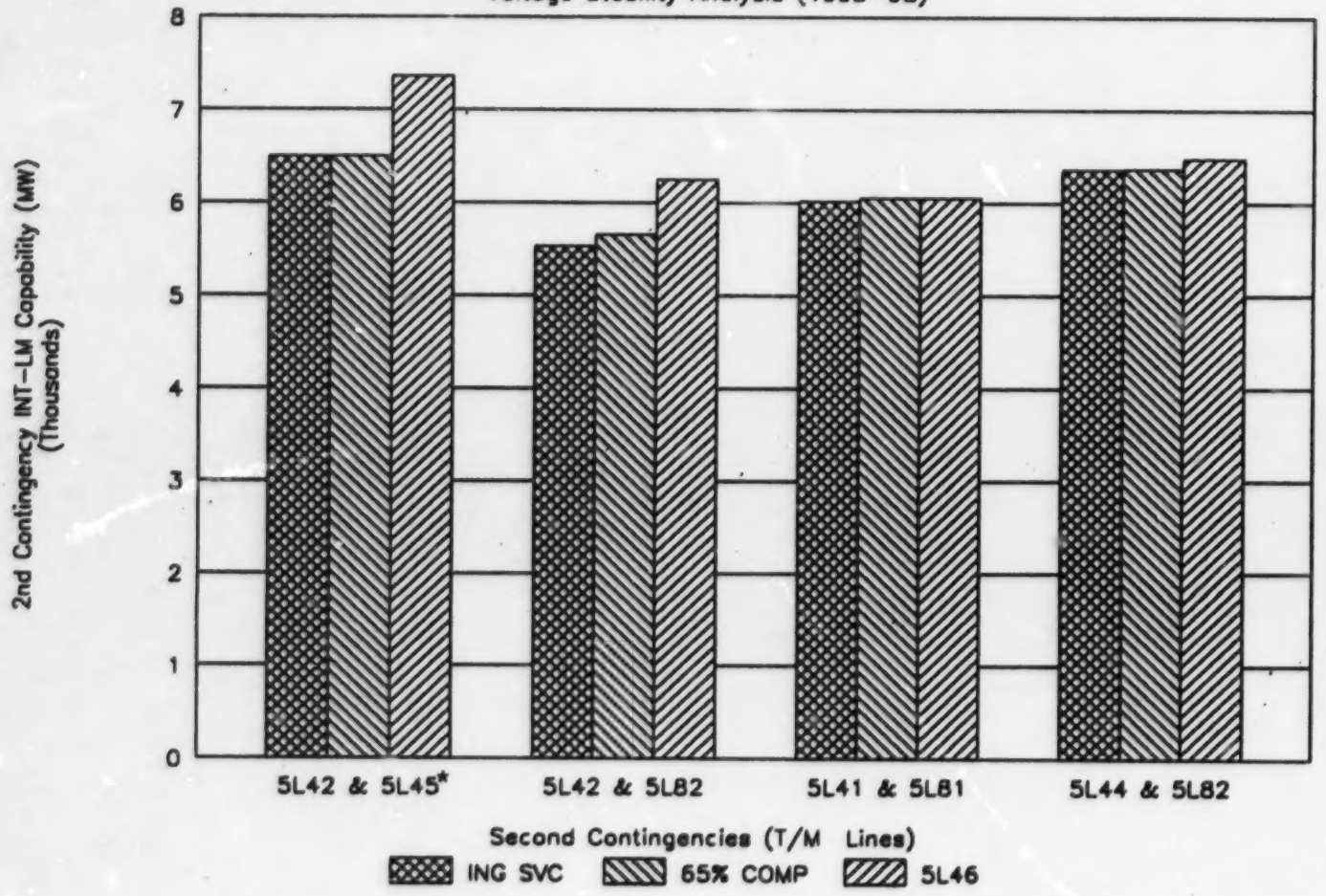
---

[14] Current exceeding 3000 amperes per overhead circuit.

[15] Current exceeding 550 amperes per cable circuit.

2nd Contingency INT–LM T/M Capability

Voltage Stability Analysis (1995–98)



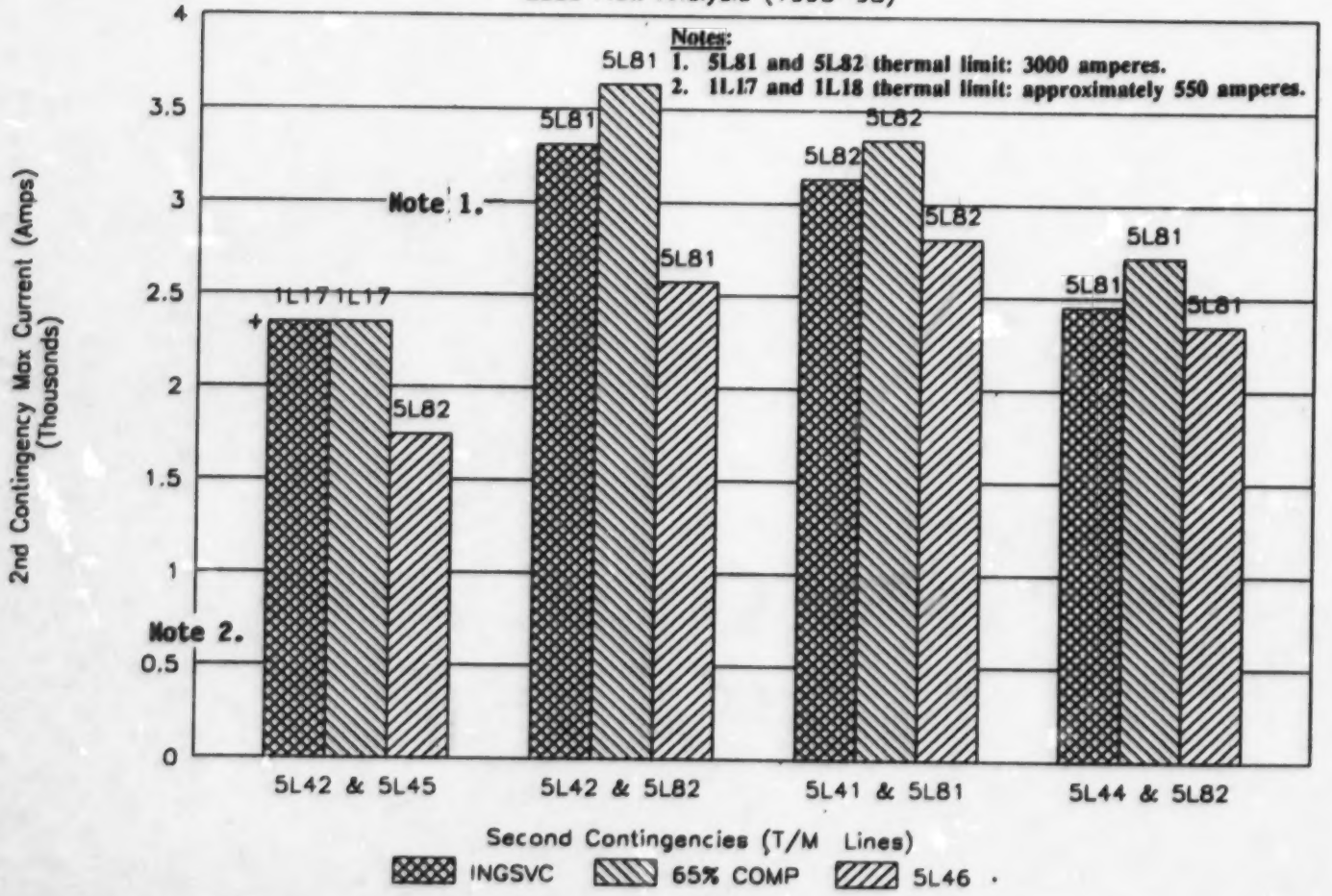
* FOR THE S/C AND SVC OPTIONS THIS EFFECTIVELY MEANS AN OUTAGE OF THE 500 KV TIE TO VANCOUVER ISLAND AND SECHELT PENNINSULA AND A LOAD REDUCTION IN THIS REGION UP TO THE MAXIMUM DEPENDABLE CAPACITY OF THE LOCAL GENERATION AND THE REMAINING PARALLEL TIES.

19-Mar-91

FIGURE 1

Second Contingency Max Current

Load Flow Analysis (1995–98)



+ Relieved by automatic load dropping on Vancouver Island within a few seconds of the second contingency.

07-Mar-91

FIGURE 2

APPENDIX 4

RELIABILITY COMPARISONS

APPENDIX 4

Reliability of Transmission System Elements

A weakness in the use of deterministic criteria for assessing the adequacy of a transmission system is that it doesn't account for differences in the reliability of different system elements. Forced outage data suggests that there are marked differences in the forced outage rates for different transmission system elements.

Figure 1

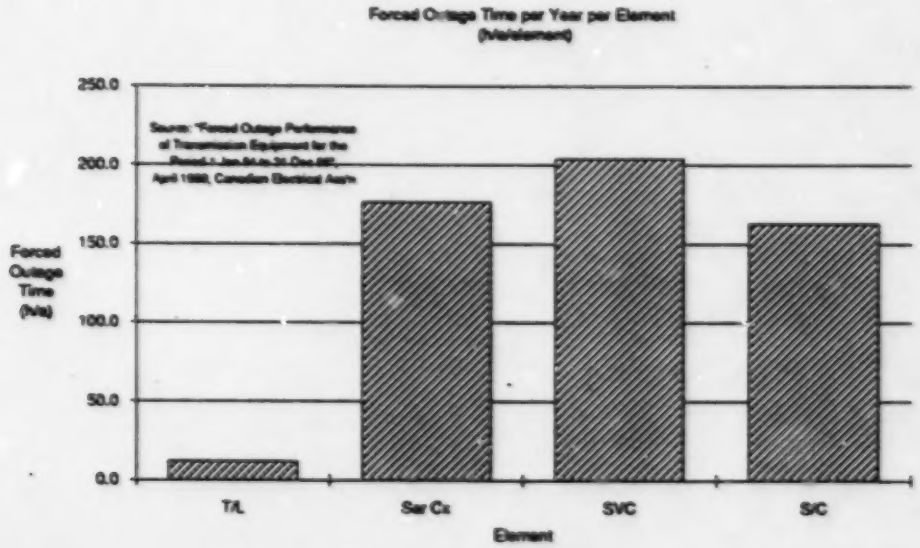


Figure 1 compares the expected forced outage time per year of:

1. A two terminal, 200 km 500 kV transmission line (T/L).
2. A 500 kV series capacitor bank (Ser Cx).
3. A static var compensator (SVC).
4. A synchronous condenser (S/C).

Figure 1 demonstrates that a 500 kV transmission line is significantly more reliable than the other three elements. SVCs, S/Cs and 500 kV series capacitor banks show similar expected forced outage times per year all of which are much higher that the expected forced outage time per year for a two terminal, 200 km 500 kV line.

For example, the expected time per year that an SVC will be forced out of service due to equipment failure is more than 16 times greater than that of a 500 kV transmission line.

Memo from Pat G. Harrington to J.S. Mumick: 91/02/27: File: 940 R-5-1
Transmission System Elements - Comparison of Reliability

The April 1990 Canadian Electrical Association publication entitled, "Forced Outage Performance of Transmission Equipment for the Period January 1, 1984 to December 31, 1988" is the source of the data upon which Figure 1 is based. The data in that publication is obtained from the major Canadian utilities. The data on 500 kV transmission lines and 500 kV series capacitor banks is exclusively B.C. Hydro data because B.C. Hydro is the only utility in Canada with such equipment. Similarly most of the SVC data is from Hydro Quebec which has far more SVCs than all of the other Canadian utilities put together.